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Electricity storage participation and modeling in short-term electricity markets

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Dissertation presented in partial fulfillment of the requirements for the degree of Doctor of Engineering Science (PhD): Electrical Engineering

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Preface

Let's take a trip down memory lane, to a snowy morning in March 2013. I had my application interview with Cedric De Jonghe and Dirk Van Hertem, during which I was amazed by Electa's track record, and the envisioned topic for the open Ph.D. position. I would have the opportunity to work on electricity storage, and do this in collaboration with major companies. As a master student it is difficult to know whether a job opportunity is "the right one", but now that my journey here has come to an end, I can honestly say that the decision to pursue a Ph.D. degree led to an amazing and intellectually enriching adventure.

I have always felt thankful to be given this opportunity, for which I would like to thank my supervisor Ronnie Belmans. Ronnie, your ability to position my research in the bigger picture of power systems definitely contributed to its quality. Thank you for always being available to meet when I asked to discuss both content-related and practical topics. While your many responsibilities may sometimes have led to meetings that were short in duration, they were always large in impact and a true source of inspiration.

I would also like to sincerely thank all members of the examination committee for their support and insights. Prof. Wollants, thank you for chairing my examination committee. Stef Proost, Chris De Groof, Dirk Van Hertem, Cedric De Jonghe, and Sauleh Siddiqui, thank you for the opportunity to pick your brains during our periodical meetings, and to steer me in the right direction. Stef, thank you to challenge my research from an economics point of view, and Chris, thank you for doing this from a finance and utility's point of view. Dirk, thank you for having me as part of your team at the HVDC colloquia and power meetings, and as a lecturer at the FPS Economy, SMEs, Self-employed, and Energy. Cedric, I owe you a special thank you. Your ability to find the fine line between providing sufficient freedom and guidance, and your deep knowledge of electricity markets, makes you the best possible mentor I could have wished for. Over the years I have grown to see you as an older brother who I could always turn to for advice. Sauleh, thank you for your enthusiasm, support, and collaboration during and after my research stays at The Johns Hopkins University. You are an incredibly talented professor with the unique skill to explain the most complex topics in an easy to understand way.

When talking about my time at The Johns Hopkins University, I also need to thank Benjamin Hobbs and Daniel Huppmann. Ben, thank you to share your world-renowned expertise. Our talks helped me in getting a better understanding of my research. Daniel, just like Sauleh you have the unique skill to convey the most complex messages in a crystal clear way. Thank you for introducing me to the wonderful world of equilibrium modeling. I would also like to thank FWO for providing me with a travel scholarship enabling these adventures.

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Finally, there are some people that deserve to be acknowledged more than anyone. Thank you to my family, in-laws, and friends, for the most welcome relaxing moments that allowed me to recharge my batteries. Mama and papa, a wholehearted thank you for always supporting me in chasing my dreams. Your warmth and unconditional support enabled me to become the person that I am today. Last but not least, I need to thank Linde more than words can say. For taking on this challenge like it was your own, for your support in stressful times, and for loving me unconditionally. I am truly blessed having you by my side.

Abstract

Electricity is a real-time product. Supply and demand, or generation and consumption, have to match exactly at any instance to support the stable operation of the power system. This results from the fact that electricity is not economically storable on a large scale. While this is challenged by techno-economic developments leading to increased and improved storage capacities, storage levels remain well below that of other energy commodities. In addition, in light of the growing importance of sustainability, there is an ongoing transition towards variable renewable energy sources. Their limited controllability and predictability result in an increasing need for flexibility, which is the ability to provide power adjustments to compensate for temporary imbalances between generation and consumption. At the same time, the flexibility offered by the generation side is threatened by closure of conventional power plants that are currently experiencing decreasing profitability. While flexibility can also be provided by flexible supply, flexible demand, and the electric grid, electricity storage is expected to play an important role to fill the flexibility gap.

This thesis studies the participation and modeling, and role and value, of electricity storage in short-term electricity markets, including day-ahead and intra-day energy markets, and real-time balancing markets. These markets are important tools to deal with the variability in the system, in which the need for flexibility is expressed and its provision is valorized. As such, they are becoming increasingly important with the ongoing integration of variable renewables. The geographical scope includes Belgium and the Central Western European region, including the French, German, and Dutch market zones next to that of Belgium.

First, the concept of electricity storage is discussed, along with a quantitative study on the role, value, and benefits of storage in the transition to, and operation of, highly renewable power systems. The former includes a discussion on the definition of electricity storage, applications for which storage systems can be used, techno-economic parameters by which storage systems can be characterized, and storage technologies that are often considered for grid integration. The latter includes the presentation of a system-wide generation expansion planning model that decides on the cost-minimizing generation mix and scheduling to meet the demand for energy and frequency control, subject to detailed operating requirements and constraints. This model is applied to a test system to derive system-independent and broadly-applicable insights on the role and value of storage, and the interdependency of flexibility sources.

Second, since understanding short-term markets is essential for analyses related to flexibility, their design rules are studied in detail along with the implications for flexibility. This is done for the four market zones of the Central Western European region, and provides insight in whether flexibility is treated consistently and appropriately among the different markets, both in time and in space. Where appropriate, desirable future market reforms are indicated.

Third, the storage participation, including its trading and operation, in short-term markets is studied. In a first study, employing storage systems for a single application is considered, namely day-ahead market arbitrage. A single-player storage operator perspective is assumed, resulting in a price-based unit commitment formulation. Detailed operating constraints are considered, and a new methodology to study the price-effect of storage actions is introduced based on so-called market resilience functions. This price-effect states that storage generally reduces price spreads by increasing low prices and decreasing high prices. In addition, a stepwise approximation to the piecewise linear market resilience functions is proposed, offering the capability to reduce computation time while providing accurate lower and upper bounds. The developed models are applied to Belgian market data to quantify the arbitrage value and price-effect. Since determining the true value of storage requires the aggregation of applications, and the co-optimization of these applications to avoid conflicting uses, in a second study the day-ahead market arbitrage models are extended to allow for the aggregation of different arbitrage opportunities in the three short-term markets. In addition, the price-effect is studied for the intra-day and real-time markets as well. These models are used to analyze the opportunities for storage in the three short-term markets and four market zones, while differences in storage value are traced back to differences in market design.

Fourth, the aggregation of applications can also be achieved through the co-operation and sharing of storage resources by different players. New markets, or market products within existing markets, to enable such storage uses, and thus the decoupling of ownership from operation, can be valuable levers to capture the true value of storage. The concept of physical storage rights is introduced, which can be auctioned to different players and entitle the holders to the right to use storage resources. Based on a case study with Belgian data, the storage value in a range of fixed a priori allocations is compared to that of allocations resulting from the proposed auction-based mechanism to show its merits.

Beknopte samenvatting

Elektriciteit is een real-time product. Productie en verbruik moeten op elk ogenblik in evenwicht zijn om de stabiele uitbating van het elektriciteitssyteem te garanderen. Dit resulteert uit het feit dat elektriciteit niet eenvoudig op grote schaal stockeerbaar is. Alhoewel dit gegeven wordt uitgedaagd door techno-economische ontwikkelingen die resulteren in een verhoogde en verbeterde opslagcapaciteit, blijft deze ver onder die van andere energiedragers. Momenteel is er in het kader van duurzaamheid een transitie aan de gang naar variabele hernieuwbare energiebronnen. Hun beperkte controlleerbaarheid en voorspelbaarheid leidt tot een groeiende nood aan flexibiliteit, wat de vaardigheid is om vermogensaanpassingen te doen om tijdelijke onbalansen tussen productie en verbruik op te vangen. Tegelijkertijd is de flexibiliteit aangeboden door de productiezijde bedreigd door de sluiting van conventionele centrales als gevolg van hun dalende winstgevendheid. Alhoewel flexibiliteit ook kan worden voorzien door flexibele productie en verbruikers, en het elektriciteitsnet, wordt verwacht dat elektriciteitsopslag een grote rol zal spelen in de flexibiliteitsvoorziening.

Deze thesis bestudeert de deelname en modellering, en rol en waarde, van opslag in korte-termijn elektriciteitsmarkten, zijnde day-ahead en intra-day energiemarkten, en real-time balanceringsmarkten. Deze markten zijn belangrijk om de variabiliteit in het systeem te beheren, waarin de nood aan flexibiliteit zichtbaar wordt en het aanbod ervan gevaloriseerd. Als zodanig winnen deze markten aan belang met het groeiende aandeel van hernieuwbare energie. De geografische scope omvat België en de Centraal-West-Europese regio, bestaande uit de Franse, Duitse, en Nederlandse marktzones bovenop de Belgische.

Eerst wordt het concept van elektriciteitsopslag toegelicht, waarna een studie volgt rond de rol en waarde van opslag in de transitie naar, en uitbating van, hernieuwbare elektriciteitssystemen. De eerste studie handelt rond de definitie van elektriciteitsopslag, toepassingen waarvoor opslagsystemen kunnen worden gebruikt, parameters waarmee ze kunnen worden beschreven, en opslagtechnologiën die typisch voor netintegratie worden beschouwd. De

tweede studie presenteert een planningsmodel dat op systeemniveau de optimale productiemix en uitbating bepaalt om aan de vraag naar energie en frequentieregeling te voldoen, gegeven gedetailleerde vereisten en beperkingen rond uitbating. Het wordt toegepast om systeemonafhankelijke inzichten in de rol en waarde van opslag, en interactie tussen flexibiliteitsbronnen, te verwerven.

Omdat een goede kennis van het marktkader van de korte-termijnmarkten essentieel is voor flexibiliteitsanalyses, worden in tweede instantie de marktregels in detail bestudeerd alsook de implicaties voor flexibiliteit. Dit wordt gedaan voor de vier marktzones van de Centraal-West-Europese regio, en biedt inzicht in hoe consistent en correct flexibiliteit behandeld wordt in de verschillende markten. Waar opportuun worden interessante hervormingen geïdentificeerd.

Nadien wordt de deelname van opslag, zijnde de trading en uitbating, in korte-termijnmarkten bestudeerd. In eerste instantie wordt een enkele toepassing bekeken, namelijk day-ahead markt arbitrage. Het genomen perspectief is dat van een enkele opslaguitbater, wat leidt tot een zogenaamde prijs-gebaseerde unit commitment formulering. Gedetailleerde beperkingen rond de uitbating worden beschouwd, alsook wordt er een nieuwe methodologie voorgesteld om het prijseffect van opslag te bestuderen, gebaseerd op zogenaamde markt resilience functies. Dit prijseffect houdt in dat opslag typisch prijsverschillen verkleint door lage prijzen te verhogen en hoge prijzen te verlagen. Er wordt tevens een trapsgewijze benadering voorgesteld voor de stuksgewijs lineaire markt resilience functies. Deze benadering kan de rekentijd aanzienlijk verlagen en tegelijk nauwkeurige boven- en ondergrenzen bekomen. De modellen worden toegepast op Belgische data om de arbitrage waarde en het prijseffect te kwantificeren. Aangezien het realiseren van de volledige waarde van opslag de aggregatie van toepassingen vereist, en de co-optimalisatie van deze diensten omdat zij conflicterend kunnen zijn, worden in tweede instantie de day-ahead markt modellen uitgebreid om meerdere arbitrage opportuniteiten in de drie korte-termijnmarkten te aggregeren. Het prijseffect wordt hier ook voor de intra-day en real-time markt bekeken. Deze uitgebreide modellen worden gebruikt om de opportuniteiten voor opslag in de drie korte-termijnmarkten en vier marktzones te analyseren, en verschillen te linken aan verschillen in marktregels.

De aggregatie van toepassingen kan ook worden bereikt door de co-uitbating en het delen van opslagmiddelen door verschillende spelers. Nieuwe markten, of marktproducten, die zulk gebruik, en dus de ontkoppeling van eigendom en uitbating, mogelijk maken, zijn waardevol om tot de volledige waarde van opslag te komen. Het concept van fysieke opslagrechten wordt geïntroduceerd, welke worden geveild aan verschillende spelers en het recht geven om opslagmiddelen te gebruiken. Gebaseerd op een illustratieve case study wordt de waarde van het voorgestelde veiling-gebaseerde mechanisme aangetoond door de bijhorende waarde van opslag te vergelijken met die van een reeks van a priori allocaties.

List of abbreviations

Acronyms

AC	Alternating current.
ACE	Area control error.
aFRR	Automatic frequency restoration reserve.
ATC	Available transfer capacity.
BES	Battery energy storage.
BRP	Balance responsible party.
BSP	Balance service provider.
CAES	Compressed air energy storage.
CAISO	California independent system operator.
CCGT	Combined cycle gas turbine.
CO_2	Carbon dioxide.
CWE	Central Western European.
DA	Day-ahead.
DC	Direct current.
DSO	Distribution system operator.
E2P	Energy-to-power.
ENTSO-E	European network of transmission system operators for electricity.
ERCOT	Electric reliability council of Texas.
FBMC	Flow-based market-coupling.
FCR	Frequency containment reserve.
FRR	Frequency restoration reserve.
FTR	Financial transmission right.
GCC	Grid control cooperation.
GEP	Generation expansion planning.
GNEP	Generalized Nash equilibrium problem.
ID	Intra-day.
IGCC	International grid control cooperation.
KKT	Karush-Kuhn-Tucker.

LDC	Load duration curve.
MCP	Mixed complementarity problem.
mFRR	Manual frequency restoration reserve.
MIBEL	Iberian electricity market.
MILP	Mixed-integer linear program(ming).
MIQP	Mixed-integer quadratic program(ming).
MRP	Market reference point.
NEP	Nash equilibrium problem.
NRV	Net regulation volume.
NYISO	New York independent system operator.
OCGT	Open cycle gas turbine.
OLS	Ordinary least squares.
OTC	Over-the-counter.
O&M	Operation and maintenance.
P2G	Power-to-gas.
PBUC	Price-based unit commitment.
PCR	Price coupling of regions.
PDF	Probability density function.
PHS	Pumped-hydro storage.
PJM	Pennsylvania - New Jersey - Maryland.
PTR	Physical transmission right.
PV	Photovoltaic.
RES	Renewable energy sources.
RLDC	Residual load duration curve.
RR	Replacement reserve.
RT	Real-time.
SI	System imbalance.
SMES	Superconducting magnetic energy storage.
SOS1	Special ordered set of type 1.
SOS2	Special ordered set of type 2.
s.t.	Subject to.
TSO	Transmission system operator.
UC	Unit commitment.
UPS	Uninterruptible power supply.
VOLL	Value of lost load.
WACC	Weighted average cost of capital.

Battery chemistries

Li-ion	Lithium-ion.
NaS	Sodium-sulfur.
Pb-acid	Lead-acid.

Va-Va	Vanadium-vanadium.
Zn-Br	Zinc-bromine.

Country codes

BE	Belgium.
DE	Germany.
FR	France.
NL	The Netherlands.
UK	United Kingdom.
US	United States.

SI and base units

J	Joule.
kg	Kilogram.
l	Liter.
s	Second.
W	Watt.
%	Percentage.
€	Currency of the eurozone.

Non-SI and non-base units

a	Year.
boe	Barrel of oil equivalent.
GW	Gigawatt.
GWh	Gigawatthour.
h	Hour.
kW	Kilowatt.
kWh	Kilowatthour.
m^3	Cubic meter.
min	Minute.
MW	Megawatt.
MWh	Megawatthour.
MWq	Megawatt quarter-hour.
rpm	Revolutions per minute.

List of symbols

In the nomenclature below, the SI or base unit is indicated for the variables and parameters. Formulas are provided assuming SI and base units as well. In contrast, input data and results are provided in commonly used units in power system engineering and power system economics, e.g., MWh instead of J. Such conversion is performed without notice throughout this thesis. Finally, all superscripts are descriptor indices, while all subscripts refer to valued indices.

Sets

$h \in \mathbb{H}$	Hourly time steps.
$i \in \mathbb{I}$	Injection technologies, $\mathbb{I} = \mathbb{ID} \cup \mathbb{II}$.
$i \in \mathbb{ID}$	Dispatchable injection technologies, $\mathbb{ID} \subseteq \mathbb{I}$.
$i \in \mathbb{II}$	Intermittent injection technologies, $\mathbb{II} \subseteq \mathbb{I}$.
$k \in \mathbb{K}$	Piecewise breakpoints.
$k \in \mathbb{K}^{\mathrm{da}}$	Piecewise breakpoints for the DA market.
$k \in \mathbb{K}^{\mathrm{rt}}$	Piecewise breakpoints for the RT market.
$l \in \mathbb{L}$	Players.
$o \in \mathbb{O}$	Offtake technologies, $\mathbb{O} = \mathbb{S}$.
$q \in \mathbb{Q}$	Quarter-hourly time steps.
$q \in \mathbb{Q}^{\mathrm{fq}}$	First quarter-hours of each considered hour, $\mathbb{Q}^{\mathrm{fq}} \subset \mathbb{Q}$.
$r \in \mathbb{R}$	Operating reserve categories, $\mathbb{R} = \mathbb{RU} \cup \mathbb{RD}$.
$r \in \mathbb{RD}$	Downward FCR, aFRR, and mFRR, $\mathbb{RD} \subset \mathbb{R}$.
$r \in \mathbb{RDA}$	Downward FCR and aFRR, $\mathbb{RDA} \subset \mathbb{RD}$.
$r \in \mathbb{RDF}$	Downward FCR, $\mathbb{RDF} \subset \mathbb{RDA}$.
$r \in \mathbb{RU}$	Upward FCR, aFRR, and mFRR, $\mathbb{RU} \subset \mathbb{R}$.
$r \in \mathbb{RUA}$	Upward FCR and aFRR, $\mathbb{RUA} \subset \mathbb{RU}$.
$r \in \mathbb{RUF}$	Upward FCR, $\mathbb{RUF} \subset \mathbb{RUA}$.
$s \in \mathbb{S}$	Electricity storage technologies, $\mathbb{S} \subseteq \mathbb{ID}$, $\mathbb{S} = \mathbb{O}$.
$t \in \mathbb{T}$	Time stamps.
$u \in \mathbb{U}_h$	Stepwise steps.

$u \in \mathbb{U}_q^{\mathrm{da}}$	Stepwise steps for the DA market.
$u \in \mathbb{U}_q^{\mathrm{rt}}$	Stepwise steps for the RT market.
$w \in \mathbb{W}$	Minimum up time set.
$x_l \in \mathbb{X}_l$	Feasible strategies in an NEP.
$x_l \in \mathbb{X}_l(x_{\text{-}l})$	Feasible strategies in a GNEP.
$z \in \mathbb{Z}$	Minimum down time set.

Variables

Binary variables

b_h	Charge/discharge state [-].
b_q^{da}	Charge/discharge state after the DA stage [-].
b_q^{id}	Charge/discharge state after the ID stage [-].
b_q^{rt}	Charge/discharge state after the RT stage [-].
$b_q^{\mathrm{bs,da}}$	Buy/sell state in the DA market [-].
$b_q^{\mathrm{bs,id,ch}}$	Buy/sell state in the hourly continuous ID market [-].
$b_q^{\mathrm{bs,id,cq}}$	Buy/sell state in the quarter-hourly continuous ID market [-].
$b_q^{\mathrm{bs,id,aq}}$	Buy/sell state in the auction-based ID market [-].
b_q^{i}	Positive/negative imbalance state [-].
$b_{h,k}^{\mathrm{pw}}$	Piecewise segment indicator [-].
$b_{h,u}^{\mathrm{sw}}$	Stepwise step indicator [-].
$b_{q,u}^{\mathrm{sw,da}}$	Stepwise step indicator for the DA market [-].
$b_{q,u}^{\mathrm{sw,rt}}$	Stepwise step indicator for the RT market [-].

Dual variables

$\mu_{l,h}^{\mathrm{c}}$	Dual to the charge power constraint [€/(s·W)].
μ_h^{c}	Price of charge power rights [€/(s·W)].
μ_t^{c}	Price of charge power rights [€/(s·W)].
μ^{c}	Price of charge power rights [€/(s·W)].
$\mu_{l,h}^{\mathrm{d}}$	Dual to the discharge power constraint [€/(s·W)].
μ_h^{d}	Price of discharge power rights [€/(s·W)].
μ_t^{d}	Price of discharge power rights [€/(s·W)].
μ^{d}	Price of discharge power rights [€/(s·W)].
$\mu_{l,h}^{\mathrm{e}}$	Dual to the storage capacity constraint [€/(s·J)].
μ_h^{e}	Price of storage capacity rights [€/(s·J)].
μ_t^{e}	Price of storage capacity rights [€/(s·J)].
μ^{e}	Price of storage capacity rights [€/(s·J)].
$\gamma_{l,h}^{\mathrm{e}}$	Dual to the intertemporal energy buffer constraint [€/(s·J)].

$\gamma^{\mathrm{g}}_{l,h}$ Dual to the available renewable power constraint [€/(s·W)].
$\gamma^{\mathrm{l}}_{l,h}$ Dual to the imbalance position constraint [€/(s·W)].
$\tau^{\mathrm{c}}_{l,h}$ Dual to the charge power rights constraint [€/(s·W)].
$\tau^{\mathrm{d}}_{l,h}$ Dual to the discharge power rights constraint [€/(s·W)].
$\tau^{\mathrm{e}}_{l,h}$ Dual to the storage capacity rights constraint [€/(s·J)].

Free variables

$\lambda^{\mathrm{da}}_{h}$ DA price [€/J].
$\lambda^{\mathrm{da}}_{q}$ DA price [€/J].
π_{l} Profit [€/s].
π^{op} Operating profit [€/s].
π^{op}_{l} Operating profit [€/s].
$\pi^{\mathrm{op,da}}$ Operating profit after the DA stage [€/s].
$\pi^{\mathrm{op,id}}$ Operating profit after the ID stage [€/s].
$\pi^{\mathrm{op,rt}}$ Operating profit after the RT stage [€/s].

Positive variables

c^{cyc} Depreciation cost [€/s].
c^{cyc}_{s} Depreciation cost [€/s].
$c^{\mathrm{cyc,da}}$ Depreciation cost after the DA stage [€/s].
$c^{\mathrm{cyc,id}}$ Depreciation cost after the ID stage [€/s].
$c^{\mathrm{cyc,rt}}$ Depreciation cost after the RT stage [€/s].
$d^{\mathrm{c}}_{l,t}$ Price-quantity demand bid for charge power rights [€/(s·W)-W].
$d^{\mathrm{d}}_{l,t}$ Price-quantity demand bid for discharge power rights [€/(s·W)-W].
$d^{\mathrm{e}}_{l,t}$ Price-quantity demand bid for storage capacity rights [€/(s·J)-J].
e_{h} Stored energy [J].
$e_{l,h}$ Stored energy [J].
$e_{s,h}$ Stored energy [J].
e_{t} Stored energy [J].
e^{da}_{q} Stored energy after the DA stage [J].
e^{id}_{q} Stored energy after the ID stage [J].
e^{rt}_{q} Stored energy after the RT stage [J].
e^{inst}_{s} Installed energy storage capacity [J].
e^{max}_{l} Storage capacity right [J].
$e^{\mathrm{max}}_{l,h}$ Storage capacity right [J].
$e^{\mathrm{max}}_{l,t}$ Storage capacity right [J].
n^{cyc} Cycling rate [s^{-1}].
$n^{\mathrm{cyc,da}}$ Cycling rate after the DA stage [s^{-1}].

$n^{\mathrm{cyc,id}}$	Cycling rate after the ID stage [s^{-1}].
$n^{\mathrm{cyc,rt}}$	Cycling rate after the RT stage [s^{-1}].
$n^{\mathrm{inj}}_{i,h}$	Number of online injection units [-].
$n^{\mathrm{off}}_{o,h}$	Number of online offtake units [-].
$n^{\mathrm{sd,inj}}_{i,h}$	Number of online injection units shutting down [-].
$n^{\mathrm{sd,off}}_{o,h}$	Number of online offtake units shutting down [-].
$n^{\mathrm{sdr,inj}}_{r,i,h}$	Number of online injection units committed to shut down to provide reserve [-].
$n^{\mathrm{sdr,off}}_{r,o,h}$	Number of online offtake units committed to shut down to provide reserve [-].
$n^{\mathrm{su,inj}}_{i,h}$	Number of offline injection units starting up [-].
$n^{\mathrm{su,off}}_{o,h}$	Number of offline offtake units starting up [-].
$n^{\mathrm{sur,inj}}_{r,i,h}$	Number of offline injection units committed to start up to provide reserve [-].
$n^{\mathrm{sur,off}}_{r,o,h}$	Number of offline offtake units committed to start up to provide reserve [-].
$p^{\mathrm{b,da}}_{q}$	Buy power in the DA market [W].
$p^{\mathrm{b,da}}_{q,u}$	Buy power in the DA market [W].
$p^{\mathrm{b,id,ch}}_{q}$	Buy power in the hourly continuous ID market [W].
$p^{\mathrm{b,id,cq}}_{q}$	Buy power in the quarter-hourly continuous ID market [W].
$p^{\mathrm{b,id,aq}}_{q}$	Buy power in the auction-based ID market [W].
p^{c}_{h}	Charge power [W].
$p^{\mathrm{c}}_{h,u}$	Charge power [W].
$p^{\mathrm{c}}_{l,h}$	Charge power [W].
p^{c}_{t}	Charge power [W].
$p^{\mathrm{c,da}}_{q}$	Charge power after the DA stage [W].
$p^{\mathrm{c,id}}_{q}$	Charge power after the ID stage [W].
$p^{\mathrm{c,rt}}_{q}$	Charge power after the RT stage [W].
$p^{\mathrm{c,max}}_{l}$	Charge power right [W].
$p^{\mathrm{c,max}}_{l,h}$	Charge power right [W].
$p^{\mathrm{c,max}}_{l,t}$	Charge power right [W].
p^{d}_{h}	Discharge power [W].
$p^{\mathrm{d}}_{h,u}$	Discharge power [W].
$p^{\mathrm{d}}_{l,h}$	Discharge power [W].
p^{d}_{t}	Discharge power [W].
$p^{\mathrm{d,da}}_{q}$	Discharge power after the DA stage [W].
$p^{\mathrm{d,id}}_{q}$	Discharge power after the ID stage [W].
$p^{\mathrm{d,rt}}_{q}$	Discharge power after the RT stage [W].
$p^{\mathrm{d,max}}_{l}$	Discharge power right [W].

$p_{l,h}^{\mathrm{d,max}}$	Discharge power right [W].
$p_{l,t}^{\mathrm{d,max}}$	Discharge power right [W].
$p_{l,h}^{\mathrm{g}}$	Power generation [W].
$p_{q}^{\mathrm{i,+}}$	Positive imbalance power [W].
$p_{q,u}^{\mathrm{i,+}}$	Positive imbalance power [W].
$p_{q}^{\mathrm{i,-}}$	Negative imbalance power [W].
$p_{q,u}^{\mathrm{i,-}}$	Negative imbalance power [W].
$p_{i,h}^{\mathrm{inj}}$	Power injection [W].
$p_{i}^{\mathrm{inst,inj}}$	Installed injection power rating [W].
$p_{o}^{\mathrm{inst,off}}$	Installed offtake power rating [W].
$p_{i,h}^{\mathrm{l,inj}}$	Power curtailment of injection units [W].
$p_{l,h}^{\mathrm{l}}$	Power curtailment [W].
p_{h}^{ls}	Load shedding [W].
$p_{o,h}^{\mathrm{off}}$	Power offtake [W].
$p_{i,h}^{\mathrm{rd,inj}}$	Decrease in injection by ramping down injection units [W].
$p_{o,h}^{\mathrm{rd,off}}$	Decrease in offtake by ramping down offtake units [W].
$p_{i,h}^{\mathrm{ru,inj}}$	Increase in injection by ramping up injection units [W].
$p_{o,h}^{\mathrm{ru,off}}$	Increase in offtake by ramping up offtake units [W].
$p_{q}^{\mathrm{s,da}}$	Sell power in the DA market [W].
$p_{q,u}^{\mathrm{s,da}}$	Sell power in the DA market [W].
$p_{q}^{\mathrm{s,id,ch}}$	Sell power in the hourly continuous ID market [W].
$p_{q}^{\mathrm{s,id,cq}}$	Sell power in the quarter-hourly continuous ID market [W].
$p_{q}^{\mathrm{s,id,aq}}$	Sell power in the auction-based ID market [W].
$p_{i,h}^{\mathrm{sd,inj}}$	Decrease in injection by shutting down injection units [W].
$p_{o,h}^{\mathrm{sd,off}}$	Decrease in offtake by shutting down offtake units [W].
$p_{i,h}^{\mathrm{su,inj}}$	Increase in injection by starting up injection units [W].
$p_{o,h}^{\mathrm{su,off}}$	Increase in offtake by starting up offtake units [W].
p_{t}^{+}	Positive exogenous power flow [W].
p_{t}^{-}	Negative exogenous power flow [W].
$r_{r,i,h}^{\mathrm{inj}}$	Reserve provision by injection units [W].
$r_{r,o,h}^{\mathrm{off}}$	Reserve provision by offtake units [W].
$r_{r,i,h}^{\mathrm{s,inj}}$	Reserve provision by online injection units [W].
$r_{r,o,h}^{\mathrm{s,off}}$	Reserve provision by online offtake units [W].
$r_{r,i,h}^{\mathrm{sd,inj}}$	Reserve provision by online injection units by shutting down [W].
$r_{r,o,h}^{\mathrm{sd,off}}$	Reserve provision by online offtake units by shutting down [W].
$r_{r,i,h}^{\mathrm{su,inj}}$	Reserve provision by offline injection units by starting up [W].
$r_{r,o,h}^{\mathrm{su,off}}$	Reserve provision by offline offtake units by starting up [W].

s_t^{c} Quantity supply bid for charge power rights [W].
s_t^{d} Quantity supply bid for discharge power rights [W].
s_t^{e} Quantity supply bid for storage capacity rights [J].
β_l Cost to obtain physical storage rights [€/s].
$\delta_{h,k}$ SOS2 variable [-].

Parameters

$A_{i,h}^{\mathrm{res}}$ Renewable power generation forecast [%].
$A_{l,h}^{\mathrm{res,abs}}$ Renewable power generation forecast [W].
$A_l^{\mathrm{res,max}}$ Installed renewable power rating [W].
$B_{q,u}^{\mathrm{sw,da}}$ Stepwise step indicator for the DA market [-].
$C_i^{\mathrm{fom,inj}}$ Fixed O&M cost of injection units [€/W].
$C_o^{\mathrm{fom,off}}$ Fixed O&M cost of offtake units [€/W].
$C_i^{\mathrm{fuel,inj}}$ Fuel cost of injection technologies [€/J].
$C_o^{\mathrm{fuel,off}}$ Fuel cost of offtake technologies [€/J].
$C^{\mathrm{inv,e}}$ Energy-component investment cost [€/J].
$C_s^{\mathrm{inv,e}}$ Energy-component investment cost [€/J].
$C_i^{\mathrm{inv,inj}}$ Power-component investment cost for injection units [€/W].
$C_o^{\mathrm{inv,off}}$ Power component investment cost for offtake units [€/W].
C_i^{l} Curtailment cost [€/W].
C^{ls} Load shedding cost [€/W].
$C_i^{\mathrm{ra,inj}}$ Ramping cost of injection units [€/W].
$C_o^{\mathrm{ra,off}}$ Ramping cost of offtake units [€/W].
$C_i^{\mathrm{sd,inj}}$ Shut-down cost of injection units [€/W].
$C_o^{\mathrm{sd,off}}$ Shut-down cost of offtake units [€/W].
$C_i^{\mathrm{su,inj}}$ Start-up cost of injection units [€/W].
$C_o^{\mathrm{su,off}}$ Start-up cost of offtake units [€/W].
$C_i^{\mathrm{vom,inj}}$ Variable O&M cost of injection units [€/J].
$C_o^{\mathrm{vom,off}}$ Variable O&M cost of offtake units [€/J].
D_h System load [W].
E^{max} Storage capacity upper bound [J].
E^{min} Storage capacity lower bound [J].
N^{cal} Calendar life [s].
$N_i^{\mathrm{cal,inj}}$ Calendar life of injection units [s].
$N_o^{\mathrm{cal,off}}$ Calendar life of offtake units [s].
N^{cyc} Cycle-life [-].
N_s^{cyc} Cycle-life [-].
$N_{h,k}^{\mathrm{sw}}$ Number of steps [-].
$N_{q,k}^{\mathrm{sw,da}}$ Number of steps for the DA market [-].

$N^{\mathrm{sw,rt}}_{q,k}$	Number of steps for the RT market [-].
$P^{\mathrm{b,da}}_{q}$	Buy power in the DA market [W].
$P^{\mathrm{b,id,ch}}_{q}$	Buy power in the hourly continuous ID market [W].
$P^{\mathrm{b,id,cq}}_{q}$	Buy power in the quarter-hourly continuous ID market [W].
$P^{\mathrm{b,id,aq}}_{q}$	Buy power in the auction-based ID market [W].
$P^{\mathrm{c,id}}_{q}$	Charge power after the ID stage [W].
$P^{\mathrm{c,max}}$	Charge power rating upper bound [W].
$P^{\mathrm{c,min}}$	Charge power rating lower bound [W].
$P^{\mathrm{d,id}}_{q}$	Discharge power after the ID stage [W].
$P^{\mathrm{d,max}}$	Discharge power rating upper bound [W].
$P^{\mathrm{d,min}}$	Discharge power rating lower bound [W].
$P^{\mathrm{i,max}}$	Imbalance power upper bound [W].
$P^{\mathrm{i,max}}_{l}$	Imbalance power upper bound [W].
P^{inj}_{i}	Typical unit size of injection units [W].
$P^{\mathrm{min,inj}}_{i}$	Minimum load level of online injection units [%].
$P^{\mathrm{min,off}}_{o}$	Minimum load level of online offtake units [%].
P^{off}_{o}	Typical unit size of offtake units [W].
$P^{\mathrm{s,da}}_{q}$	Sell power in the DA market [W].
$P^{\mathrm{s,id,ch}}_{q}$	Sell power in the hourly continuous ID market [W].
$P^{\mathrm{s,id,cq}}_{q}$	Sell power in the quarter-hourly continuous ID market [W].
$P^{\mathrm{s,id,aq}}_{q}$	Sell power in the auction-based ID market [W].
$R^{\mathrm{div}}_{h,k}$	Remainder [-].
$R^{\mathrm{c,do}}$	Downward ramp rate in charge state [%/s].
$R^{\mathrm{c,up}}$	Upward ramp rate in charge state [%/s].
$R^{\mathrm{d,do}}$	Downward ramp rate in discharge state [%/s].
$R^{\mathrm{d,up}}$	Upward ramp rate in discharge state [%/s].
$R^{\mathrm{en}}_{r,i}$	Endogenous reserve requirement [%].
R^{ex}_{r}	Exogenous reserve requirement [W].
$R^{\mathrm{m,inj}}_{i}$	Ramp rate of injection units for reserve provision [%/s].
$R^{\mathrm{m,off}}_{o}$	Ramp rate of offtake units for reserve provision [%/s].
R^{nrv}_{q}	Net regulation volume [J].
$R^{\mathrm{s,inj}}_{i}$	Spinning ramp rate of injection units for energy services [%/s].
$R^{\mathrm{s,off}}_{o}$	Spinning ramp rate of offtake units for energy services [%/s].
$R^{\mathrm{s,r,inj}}_{r,i}$	Ramp rate of injection units for specific reserve categories [%].
$R^{\mathrm{s,r,off}}_{r,o}$	Ramp rate of offtake units for specific reserve categories [%].
$R^{\mathrm{sd,inj}}_{i}$	Shut-down ramp rate of injection units for energy services [%/s].
$R^{\mathrm{sd,off}}_{o}$	Shut-down ramp rate of offtake units for energy services [%/s].
$R^{\mathrm{su,inj}}_{i}$	Start-up ramp rate of injection units for energy services [%/s].
$R^{\mathrm{su,off}}_{o}$	Start-up ramp rate of offtake units for energy services [%/s].
S^{res}	RES generation target [%].

S^{tar}	Target step height [€/J].
$S^{\mathrm{tar,da}}$	Target step height for the DA market [€/J].
$S^{\mathrm{tar,rt}}$	Target step height for the RT market [€/J].
$S_{h,k}^{\mathrm{upd}}$	Updated step height [€/J].
$T_r^{1,\mathrm{r}}$	Allowed ramp duration to provide reserve [s].
$T_r^{2,\mathrm{r}}$	Duration of the provision of reserve at contracted power [s].
T^{h}	Hourly time step length [s].
$T_i^{\mathrm{mdt,inj}}$	Minimum down time of injection units [s].
$T_o^{\mathrm{mdt,off}}$	Minimum down time of offtake units [s].
$T_i^{\mathrm{mut,inj}}$	Minimum up time of injection units [s].
$T_o^{\mathrm{mut,off}}$	Minimum up time of offtake units [s].
T^{q}	Quarter-hourly time step length [s].
$V_q^{\mathrm{id,ch}}$	Trading volume in the hourly continuous ID market [J].
X_k^{pw}	(Dis)charge volume according to the piecewise function [J].
$X_{h,u}^{\mathrm{sw,lo}}$	Step volume lower bound [J].
$X_{q,u}^{\mathrm{sw,lo,da}}$	Step volume lower bound in the DA market [J].
$X_{q,u}^{\mathrm{sw,lo,rt}}$	Step volume lower bound in the RT market [J].
$X_{h,u}^{\mathrm{sw,up}}$	Step volume upper bound [J].
$X_{q,u}^{\mathrm{sw,up,da}}$	Step volume upper bound in the DA market [J].
$X_{q,u}^{\mathrm{sw,up,rt}}$	Step volume upper bound in the RT market [J].
$Y_{h,k}^{\mathrm{pw}}$	Price according to the piecewise function [€/J].
$Y_{h,u}^{\mathrm{sw}}$	Price according to the stepwise function [€/J].
$Y_{q,u}^{\mathrm{sw,da}}$	DA price according to the stepwise function [€/J].
$Y_{q,u}^{\mathrm{sw,rt,+}}$	Long imbalance price according to the stepwise function [€/J].
$Y_{q,u}^{\mathrm{sw,rt,-}}$	Short imbalance price according to the stepwise function [€/J].
η^{c}	Charge efficiency [%].
η^{d}	Discharge efficiency [%].
η_s^{inj}	Injection efficiency [%].
η_s^{off}	Offtake efficiency [%].
η^{rt}	Roundtrip efficiency [%].
λ_t^{b}	Buy price [€/J].
λ_t^{s}	Sell price [€/J].
$\lambda_h^{\mathrm{da,o}}$	Initial DA price [€/J].
$\lambda_q^{\mathrm{da,o}}$	Initial DA price [€/J].
$\lambda_q^{\mathrm{id,ch,o}}$	Initial price in the hourly continuous ID market [€/J].
$\lambda_q^{\mathrm{id,cq,o}}$	Initial price in the quarter-hourly continuous ID market [€/J].
$\lambda_q^{\mathrm{id,aq,o}}$	Initial price in the auction-based ID market [€/J].
$\lambda_h^{\mathrm{rt,o}}$	Initial imbalance price [€/J].
$\lambda_q^{\mathrm{rt,+,o}}$	Initial long imbalance price [€/J].
$\lambda_q^{\mathrm{rt,-,o}}$	Initial short imbalance price [€/J].

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Chapter 1

Introduction

Context, motivation, road towards this thesis, scope, outline, and contributions

1.1 Context and motivation

Electricity differs fundamentally from other energy commodities (e.g., gas, oil, coal), as it is very much a real-time (RT) product. The supply and demand, i.e., generation and consumption, have to match exactly at every instance to support the stable operation of the power system and prevent involuntary load shedding and blackouts. As electricity is not economically storable on such a large scale as other commodities, generally, electric energy needs to be generated at the same time as it is consumed (or consumed at the same time as it is generated). This conventional truth is challenged by new techno-economic developments leading to increased and improved storage capacities, but even then storage levels still remain well below that of other energy commodities. To illustrate this, Table 1.1 compares the currently available storage resources for electricity, gas, and oil in Belgium, based on data from [1, 2, 3].[1] At the Belgian average hourly electricity consumption rate of 9.4 GWh/h, enough electricity can be stored to meet consumption for 0.6 h.[2] For the average hourly gas and oil consumption rates, storage durations of 421.5 h and 2721.0 h are available, respectively.

[1] Using a conversion factor of 10 kWh/m^3 for gas, and 1629 kWh/boe for oil.

[2] This does not take into account the installed discharge power rating, which would further limit this number, thereby making this comparison illustrative.

Table 1.1: Electricity, gas, and oil consumption rates, storage capacities, and storage durations, 2015, Belgium.

	Electricity	Gas	Oil
Annual consumption [GWh/a]	82 000.0	151 000.0	393 020.7
Average hourly consumption [GWh/h]	9.4	17.2	44.9
Available storage capacity [GWh]	5.8	7 250.0	122 175.0
Average available storage duration [h]	0.6	421.5	2 721.0

For decades, the electricity industry was centrally planned and operated by public or private vertically integrated and regulated utilities that had a geographic monopoly. They were responsible for the generation, transmission, distribution, and retail of electricity. Due to the promise of efficiency gains in the form of lower costs and prices, and in line with transitions in other industries, a liberalization process started, in Europe in the 1990s. In essence, this liberalization process includes the (1) decoupling of generation and retail from transmission and distribution, (2) introduction of competition and energy markets for generation and retail, (3) installation of natural monopolies for transmission and distribution, (4) organization of balancing markets as a tool for grid operators to keep the system balanced, and (5) installation of regulators to monitor both the market-based and regulated activities [4, 5].

In the liberalized era, different players (i.e., generators, traders, retailers,[3] aggregators,[4] grid operators,[5] and large consumers) meet (virtually) in wholesale energy and balancing markets to see whether a beneficial transaction can be made that gives them an advantage (or at least no disadvantage) [4]. These markets have undergone many design changes since the start of the liberalization, and still undergo such changes at a rapid pace. They can be categorized in long-term and short-term markets. Energy trading can start up to a few years before delivery in the long-term forward and future markets, which usually continue until one day before physical generation and consumption. In contrast, short-term electricity markets take place from the day-ahead (DA) stage onwards. These markets include DA, intra-day (ID), and RT balancing markets. In Europe, the first two are managed by power exchanges, while the third is operated by the local transmission system operator (TSO) [6].

Historically, electricity was generated by large centralized and controllable thermal (e.g., gas, oil, coal, nuclear) and hydro power plants to match the

[3] Retailers buy electricity on the wholesale energy market, and sell it in the retail energy market to (small) consumers not participating in the wholesale energy market themselves.

[4] Aggregators gather capacities of consumers, distributed generation, and storage, and aggregate these to provide services in the wholesale energy and balancing markets.

[5] Grid operators participate in balancing markets, not in wholesale energy markets.

inflexible consumption, with the help of fuel storage and pumped-hydro storage (PHS) to compensate for the variability of consumption and flexibility limitations of conventional power plants [6]. The consumption was (and largely still is) inflexible as it was almost completely unresponsive to wholesale energy price fluctuations, since the latter were not passed on to consumers [7]. Furthermore, the consumption is variable in two ways: expected variability originates from daily, weekly, and seasonal patterns, while unexpected variability follows from its uncertain nature. The inflexibility of conventional generation lies in its techno-economic operating constraints (i.e., minimum up and down times, start-up and shut-down costs, minimum load requirements, and ramp rates and costs). In such conventional power systems, the objective was twofold: achieving both a reliable and an affordable supply. In contrast, the objective in current power systems is threefold, with a supply that is reliable, affordable, and sustainable [8]. Trying to meet all three objectives in a balanced way represents the challenge of current power systems.

In light of the growing importance of sustainability, there is an ongoing transition towards variable renewable energy sources (RES), i.e., wind turbines and photovoltaic (PV) systems, challenging the operation of the power system. Their limited controllability and predictability results in an increasing need for flexibility, i.e., the ability to provide upward and downward power adjustments to compensate for temporary imbalances between generation and consumption [9, 10]. At the same time, the flexibility offered by the generation side is threatened by closure of conventional power plants that are currently experiencing decreasing profitability due to lower electricity prices and a limited number of operating hours, resulting from the so-called merit-order effect of variable RES with close-to-zero marginal cost [11, 12]. Further, a paradigm shift is taking place from a situation where generation was dispatched to follow inflexible consumption at all times, to a situation in which flexibility is provided by both generation and consumers, the latter through flexible consumption processes. However, there is a need for electricity storage as well to fill the remaining flexibility gap, and for the further development of interconnection capacity and integration of adjacent markets to access flexible resources in neighboring regions (Fig. 1.1) [13]. All flexibility sources are able to provide power adjustments by interacting with some kind of energy buffer, and although they may differ based on technical and economic characteristics, no source is necessarily superior to another. Their value depends on the chosen application and accompanying required technical performance, and on the cost [14].

Electricity storage is a subject currently undergoing intense study and debate. However, this interest is not new. From the 1960s to the 1980s, this was the case as well, with the vast majority of PHS capacity, which is the most installed storage technology with $\geq 99\,\%$ of global capacity, being constructed during this period to complement the development of inflexible nuclear power plants, and due to relatively high fuel costs for peak generators. Since in the late 1980s and 1990s nuclear development slowed down, and fuel costs for peak generators decreased, PHS development decreased significantly [15, 16]. Siting difficulties and environmental impact presented additional barriers for the further development of PHS [17, 18]. The current renaissance of electricity storage, both in research and industry, can be attributed to a combination of interesting techno-ecomic developments in storage technologies, and increasing flexibility needs due to “new” relatively inflexible technologies, i.e., variable RES. Wind power plants and PV systems are not at all subject to the same level of operational constraints as nuclear plants, but their inflexibility lies in their dependence on weather conditions and partial unpredictability. Due to techno-economic constraints of power plants, and limited ability to foresee RES generation, outages of power plants and grid elements, and load behavior, it is in short-term electricity markets where this increased need for flexibility is most apparent, and where storage is financially rewarded for its flexibility [6].

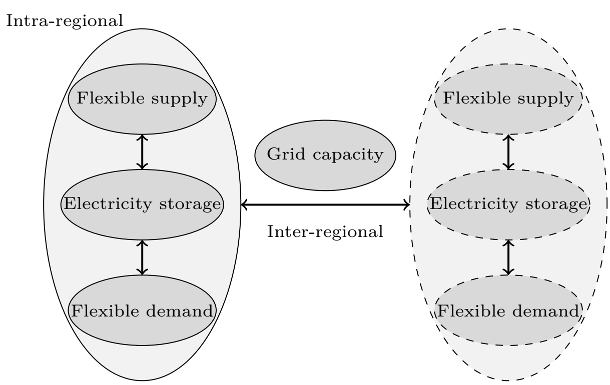

Figure 1.1: Overview of the three power system flexibility sources, and the grid, which serves as a “flexibility vehicle” enabling the access to these sources across regions.

The ongoing transition in power systems towards a more sustainable electricity supply, techno-economic developments in electricity storage technologies, and continuously changing design of the short-term electricity markets, set the scene for this work. While pure engineering studies continue to contribute in decreasing the investment cost, and improving the technical capabilities of electricity storage technologies and technical aspects of their grid integration, this work is positioned at the intersection of engineering, economics, and operations research. It aims to provide novel insights in the participation and modeling of electricity storage in short-term electricity markets, and power systems in general, experiencing increasing shares of variable RES in the generation mix.

1.2 Road towards this thesis

Both electricity markets and electricity storage are key research topics for the energy groups at KU Leuven, and for EnergyVille, which unites the energy research of KU Leuven, VITO, imec, and UHasselt. As such, previous works have been done in both fields by several of my predecessors at Electa,[6] many under the supervision of Ronnie Belmans. This thesis further builds upon their works. In particular, the dissertations of Leonardo Meeus [19], Leen Vandezande [20], Cedric De Jonghe [7], Kristof De Vos [21], Frederik Geth [14], and Arne van Stiphout [22] deserve special mentioning.

As there is a lot of interest in both electricity markets and electricity storage from industry and policy-makers as well, this thesis benefited from the ample opportunities at KU Leuven/EnergyVille for interaction with, and exposure to, such organizations. More specifically, this work has been inspired, and partly also made possible, by research projects conducted for (1) DEME, Engie, and Ackermans & van Haaren, and (2) the Belgian Federal Public Service Economy, SMEs, Self-employed, and Energy.[7]

International interactions and collaborations have contributed to this thesis as well. Insights from, and discussions at, conferences, colloquia, courses, seminars, and symposia, in Germany, Italy, Portugal, the United Kingdom (UK), and the United States (US), and an extended period abroad as visiting researcher in the US at The Johns Hopkins University with Sauleh Siddiqui and Benjamin F. Hobbs, have helped in making this thesis a contribution to the scientific literature on electricity storage and electricity markets.

1.3 Scope, outline, and contributions

This thesis aims to study the participation and modeling, and role and value, of electricity storage in short-term electricity markets, including DA and ID wholesale energy markets,[8] and RT balancing markets. These markets are important tools to deal with the variability in the system, in which the need for flexibility is expressed and its provision is valorized. As such, they can also be referred to as “flexibility markets”, and they are becoming increasingly important with the ongoing integration of variable RES. The focus is on Belgium

[6] Electa stands for the Research Group Electrical Energy and Computer Architectures, within the Department of Electrical Engineering (ESAT) of the KU Leuven.

[7] FOD Economie, KMO, Middenstand, en Energie.

[8] In the context of this thesis, DA and ID markets refer to those organized by the power exchanges. Bilateral over-the-counter (OTC) trading, in which market players agree on a trade contract by directly interacting with each other, is not in the scope of this thesis.

(BE) and the Central Western European (CWE) region, which, consistent with common definitions, includes the Belgian, French, German, and Dutch market zones. By doing so, this thesis aims to contribute to the scientific literature with novel insights to tackle current and future challenges, and it intends to enable more informed decision-making by market participants (i.e., storage operators and investors), and market organizers, coordinators, and facilitators (i.e., policy-makers, power exchanges, and system operators).

The major contributions of this work can be found in Chapter 3 to Chapter 7, each chapter being a peer-reviewed journal publication in either its published form (Chapter 3, Chapter 4, Chapter 5, and Chapter 7) or submitted form (Chapter 6). Aside from these five articles, three other peer-reviewed journal publications that are not included in this thesis are a result of the work performed during the course of this Ph.D. research. They can be found in the list of publications, together with other contributions.

Thesis storyline and chapter positioning

First, in Chapter 2 the concept of electricity storage is discussed. Afterwards, Chapter 3 digs deeper in the concept of storage by providing a quantitative study on its system-level role, value, and benefits in the transition to, and operation of, highly renewable power systems. After these discussions, its participation in the short-term markets is studied from a storage operator's perspective. For such studies to be successful, and to give them an extra dimension, a deep understanding of the functioning and design of the short-term markets, and possible future changes, is imperative. As such, Chapter 4 first reviews the design of these markets in the CWE region and analyzes the implications for flexibility. Chapter 5 and Chapter 6 then study the storage participation, including its trading and operation, in these markets. In Chapter 5, storage systems are employed for a single application, i.e., day-ahead market arbitrage. However, determining the true value of storage requires the aggregation of applications, and their co-optimization as use for one might interfere with use for others. As such, Chapter 6 extends the day-ahead market arbitrage models to allow for the aggregation of arbitrage opportunities in the three short-term markets. These models are used to analyze and understand the opportunities for storage in the three short-term markets, and their combination, of the four CWE market zones, while differences are linked to differences in market design rules. The aggregation of applications can not only be achieved by one player, but also through the co-operation and sharing of storage resources by different players. As such, Chapter 7 discusses the design of a new market, or market product within existing markets, to enable such a storage use, and thus also the decoupling of storage investment and ownership from its trading and operation.

Fig. 1.2 classifies Chapter 2 to Chapter 7 according to two dimensions: the nature of their main contributions, and the nature of their analyses. In what follows, each chapter's content will be highlighted in more detail.

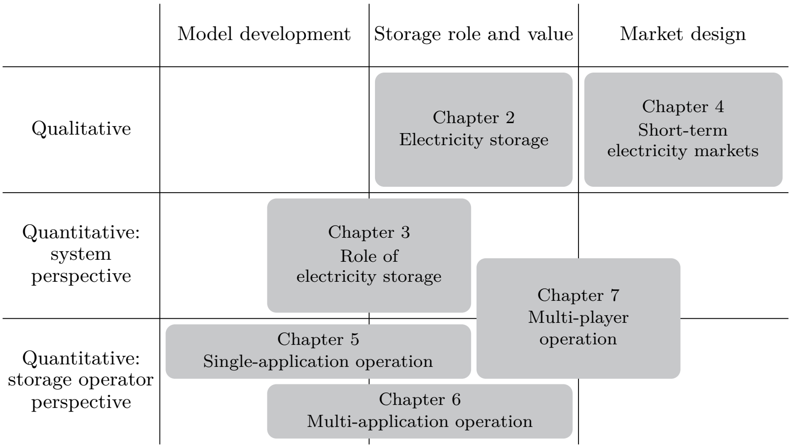

Figure 1.2: Classification of Chapter 2 to Chapter 7 according to the nature of the main contributions (left-to-right) and performed analyses (top-to-bottom).

Chapter 2: Electricity storage

Before continuing to the article-based chapters of this thesis, Chapter 2 provides a comprehensive introduction to electricity storage, accessible to a broad audience, and in part inspired by two contributions: a book chapter and an industry report. It provides a definition for electricity storage, and a discussion and overview of the (1) applications for which storage systems can be used, (2) techno-economic characteristics by which storage systems can be described, and (3) storage technologies commonly discussed for grid integration.

Chapter 3: Role of electricity storage

Context and motivation

Before moving on to the true market-based analyses of this work in Chapters 4 to 7, Chapter 3 presents a system-perspective view on the role and benefits of storage in RES-based systems for increasing RES shares, in both the (1) short-term scheduling and operation phases, and (2) long-term planning phase.

To be able to gain these insights in the role and value of storage, short-term operating constraints and requirements, which are becoming increasingly important in the context of RES-driven power systems, have to be accurately represented in long-term planning models. However, large problem sizes and computational barriers have limited the extent to which they are included in conventional generation planning models. As such, they typically include a simplified representation of short-term system operation and its costs, through low temporal and operational detail.

Scope and contributions

The article in Chapter 3 presents the development of a long-term generation planning model including an accurate representation of short-term operation with high operational and temporal detail, that minimizes total cost. Whereas short-term system operation is generally analyzed using a mixed-integer plant-level formulation of the unit commitment (UC) problem, a more computational-friendly formulation of the UC problem needs to be included next to the investment problem within a planning model with high temporal detail. This is because of the many and elaborate techno-economic constraints, and especially because of the many binary commitment decisions for each unit for each time step. In Chapter 3, short-term operation is modeled through a continuous relaxation of the technology-clustered formulation of the UC problem, which includes detailed frequency control reserve sizing, allocation, and supply.

This model is applied to a test system with system load and RES generation characteristics from the Belgian power system in a greenfield setting, i.e., assuming no pre-existing capacities. The aim is not to determine likely deployment scenarios or address optimal pathways towards the future, but abstract from an actual system with capacity legacy to derive broadly applicable conclusions on the benefits and role of storage at different RES penetration levels, and to gain insight in the interdependency between flexibility options. Both PHS and battery energy storage (BES) is considered, and their role in providing energy services and frequency control is investigated.

Chapter 4: Short-term electricity markets

Context and motivation

In the CWE region, the need for and valorization of flexibility in electric energy supply and demand is primarily expressed in the short-term markets, including DA, ID, and RT balancing markets. Due to the ongoing integration of variable RES, the variability in the system is increasing, making these markets increasingly important to keep the system balanced at different time scales. A good understanding of their design, as well as of new developments, is essential for analyses of the need for and supply of flexibility.

Although the design of short-term markets in the CWE region has been discussed before, previous works focus on individual or a limited selection of (1) design parameters, (2) sequential markets, or (3) geographical market zones. In addition, the extent to which the market design affects the needs for and rewards to flexibility is not considered. An integrated discussion of design parameters, and their interaction with flexibility, for all three short-term markets and all four CWE market zones has thus not been provided before.

Scope and contributions

The article in Chapter 4 answers two research questions. First, how are the markets related to flexibility, i.e., the short-term markets, designed in the CWE region? Second, how do these markets express the need for and reward the supply of flexibility? The answers to these research questions provide insight in whether flexibility is treated consistently and appropriately among the different geographical and sequential markets. For each market, the focus is on the key design features and parameters.

The intent is to encourage policy-makers to consider market reforms that would facilitate the integration, availability, or valorization of flexibility, while also contributing to the decision-making of flexibility investors and operators. Furthermore, the article in Chapter 4 is a key reference for power system modelers for three reasons: to better understand (1) market conditions under which generators, consumers, and system operators have to operate, (2) results of flexibility valuation models, and (3) the impact of new market design rules on the value of flexibility.

After this in-depth discussion of the design of short-term markets, we move on to the participation of electricity storage in these markets in Chapters 5 and 6, and to the discussion of an innovative type of participation in Chapter 7.

Chapter 5: Single-application operation

Context and motivation

Electricity storage plants can be used for many applications, with DA market arbitrage, i.e., the capturing of DA price spreads over time, being one of the most studied ones. The employed approaches range from a system perspective to an individual storage operator perspective. The latter, in which storage plants are scheduled to maximize profit based on price signals, is typically referred to as the price-based UC (PBUC) formulation of the arbitrage problem.

Generally there are two main assumptions in PBUC formulations: the perfect vs. imperfect price foresight assumption, which defines the operator's assumed knowledge of future prices, and the price-taking vs. price-making assumption,[9] defining whether the operator recognizes that its actions may have an impact on those prices. Additional storage capacity generally reduces price spreads by increasing off-peak prices when charging as well as decreasing on-peak prices when discharging. In price-taker PBUC models the storage operator is assumed to self-schedule its (dis)charge actions against a set of expected prices, while in price-maker PBUC models this self-scheduling occurs given a set of expected market prices and price-effect data that reflects how those prices react to changes in quantity. A large share of the literature assumes perfect foresight of future prices, and no price-effect with a price-taker approach: i.e., the storage plant to be small enough to not affect prices, or the prices to already include the storage plant's participation. While a relaxation of the perfect foresight assumption has been studied extensively, much less attention has been given to the study of the price-effect of storage transactions. Furthermore, while the existing methodologies for the price-effect provide insight in the arbitrage value and operation of large storage capacities, they include rather conceptual and simplified price-effects due to a lack of market data or a different research scope.

Scope and contributions

The article in Chapter 5 provides a comprehensive PBUC formulation of the arbitrage problem including detailed operating constraints, and the presentation of a new methodology to account for the price-effect of storage actions. This is done by considering real-world data, published in the form of hourly piecewise linear relationships between quantity and price based on submitted bids, which are referred to as market resilience functions. This is the most detailed available price-effect data, as it is obtained by the power exchange running the market-clearing algorithm again for alternative scenarios. It takes into account the (1) aggregated supply and demand curves, (2) cross-border interaction through market-coupling, and (3) dynamics of complex orders. Since this data is only available ex-post, its application lies in (1) estimating the upper limit to the arbitrage value of additional storage capacity in a certain market given current

[9] This is sometimes also referred to as the "exogenous price" vs. "price as a function of the considered player's decisions" assumption.

conditions, and (2) the evaluation of the performance of the price-taking and price-making assumptions based on more simplified price-effects.

In addition, as the piecewise linear nature of the market resilience data poses computational challenges, a stepwise approximation is proposed which reduces computational effort significantly, i.e., from mixed-integer nonconvex quadratic programming (nonconvex MIQP) to mixed-integer linear programming (MILP), while providing accurate lower and upper bound approximations to the piecewise linear results. The analyses are executed for the Belgian DA market. The results show the validity of the stepwise approximation, and the impact of the price-effect on the operation and DA market arbitrage value of electricity storage.

Chapter 6: Multi-application operation

Context and motivation

Even though there is an increasing demand for flexibility and multiple markets and applications exist for storage to participate in, recent studies point to difficult business cases. The lack of the aggregation, or at least of an efficient aggregation, of applications in a single operation strategy is usually identified as a major barrier. This may be due to the presence of historical operation patterns, complexity of revenue stacking, and accompanying risk. As such, storage valuation models often underestimate the storage value due to the focus on only a single application. Furthermore, most of the studies that do focus on the aggregation of different applications, do not allocate the storage resources by means of a continuous optimization process. Determining the true value of storage requires the aggregation of multiple applications while accounting for the interdependence between revenue streams. The latter means that the value of individual applications cannot simply be added together, but need to be co-optimized since different services can interfere with each other.

Scope and contributions

The article in Chapter 6 extends the work and results presented in Chapter 5, and contributes to the current literature on electricity storage valuation in short-term markets through three aspects.

First, PBUC model formulations are provided that allow to aggregate multiple arbitrage opportunities for electricity storage in a single operation strategy. All three short-term markets, i.e., the DA, ID, and RT balancing market, are considered, as well as the opportunity to capture three types of price differences:

(1) over time in a single market for all three markets, (2) over the three short-term markets for the same time step, and (3) over time over the three short-term markets. The developed models allocate a storage plant's power and energy ratings across the three short-term markets and three arbitrage types for each time step, according to a daily performed multiperiod optimization.

Second, the price-effect of additional storage capacity has been considered before in previous studies for the DA market (e.g., Chapter 5) with various levels of detail, but not for the ID or RT balancing market. The article in Chapter 6 studies the price-effect with high detail for not only the DA market, but also for the ID market, and for the RT balancing market by using custom-made piecewise linear RT market resilience functions, based on real-world data.

Third, the developed models are applied to the four market zones of the CWE region, thereby providing insight in the extent to which the three short-term markets, and their combination, in these market zones are potentially interesting for electricity storage arbitrage. This is intended to support market participants in storage investment and operating decisions, and to inform policy-makers about the impact of market design on the electricity storage arbitrage value.

Chapter 7: Multi-player operation

Context and motivation

Applications can not only be aggregated by one market player, but also over multiple market participants. However, the sharing and operation of storage resources by different players has only been studied to a very limited extent.

Scope and contributions

The article in Chapter 7 discusses the development of a new product to share and co-operate storage resources among multiple players. It is based on the design of a periodically organized auction with sequential market-clearings to allocate storage resources (i.e., charge and discharge power rating, energy capacity) through so-called "physical storage rights" between different players and accompanying applications. Similar to the case of explicit auctioning of cross-border capacity through physical transmission rights (PTRs), first the right to use resources is auctioned, after which players can use these resources.

Such auctions can serve both settings where (1) multiple players share common storage plants and (2) multiple suppliers of storage resources and prospective consumers meet to trade physical storage rights. Players may be incentivized to participate as they can share the investment cost, mitigate risk, exploit economies of scale, overcome regulatory barriers, and merge time-varying and player-dependent flexibility needs.

An illustrative case study is provided in which three players share storage resources that are allocated through a daily auction with hourly market-clearings. The presented auction-based mechanism allocates the limited storage resources to the most valuable application(s) for each market-clearing. First, the three players' individual PBUC optimization problems are formulated, including both individual and shared constraints. The shared constraints limit the players' combined physical storage rights by the maximum available rights, and allow an auctioneer to allocate them. Second, the individual problems are combined in an equilibrium problem. Such a problem allows to study the interaction between a set of interrelated market players. More specifically, because of the shared constraints, a Generalized Nash equilibrium problem (GNEP) is considered. The GNEP is solved by formulating the problem as a mixed complementarity problem (MCP). This is done by deriving the Karush-Kuhn-Tucker (KKT) conditions of each player's optimization problem and solving them simultaneously.

Chapter 8: Conclusions

Chapter 8 restates the main contributions, findings, and conclusions of this thesis. Based on the obtained insights, it also suggests directions for further research on electricity storage and electricity markets.

Chapter 2

Electricity storage

Electricity storage applications, characteristics, and technologies

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Inspired by two publications, including a book chapter [23] and an industry report [24]:

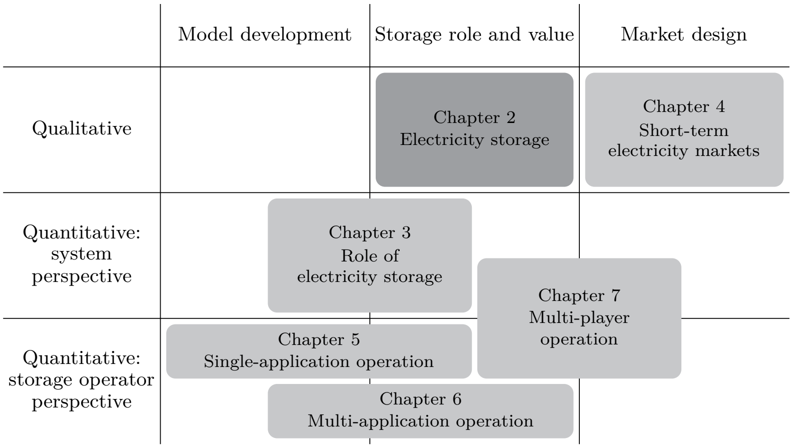
[23] T. Brijs, A. Belderbos, K. Kessels, D. Six, R. Belmans, F. Geth, Energy storage participation in electricity markets, Energy Storage Handbook, Wiley. Accepted for publication (2016).

The first author is the main author of this book chapter. It is elaborated in cooperation with the second and last author, with support and/or supervision from the third, fourth, and fifth author. The contributions of the first author include the writing of the storage applications section, and the co-writing of the storage characteristics and technologies sections.

[24] T. Brijs, K. De Vos, J. Driesen, Studie inzake de mogelijkheden tot opslag van elektriciteit, Tech. rep., FOD economie, KMO, middenstand, en energie, Brussels, Belgium (2015).

The first author is the main author of this industry report. It is elaborated in cooperation with the second author, under supervision of the third author, and with support of other researchers at EnergyVille. It is presented by the second author at a workshop organized by the Belgian Federal Public Service Economy, SMEs, Self-employed, and Energy.

Positioning:



2.1 Introduction

Electricity storage refers to systems, bidirectionally coupled with the power system, which buffer energy. It includes both systems in which the electricity consumption (i.e., charging) and generation (i.e., discharging) sides are physically located at one site, e.g., PHS plants, or at multiple locations, i.e., power-to-gas (P2G) systems in combination with a gas turbine or fuel cell [13].

The storage of electricity represents a combination of three functions [3, 9]: consuming electricity, accumulating the energy in some form, and generating electricity. Only part of the consumed electric energy is converted to energy stored in the buffer during charging because of a charge efficiency $0 < \eta^{\mathrm{c}} \leq 1$, while only part of the stored energy is converted back into electric energy during discharging because of a discharge efficiency $0 < \eta^{\mathrm{d}} \leq 1$. The buffered energy may also increase and decrease independent of the grid through exogenous power flows $p_t^{+} \geq 0$ (addition) and $p_t^{-} \geq 0$ (removal), e.g., water inflow and evaporation in the upper reservoir for PHS plants. The general power balance of storage plants that consume electric power $p_t^{\mathrm{c}} \geq 0$ and generate electric power $p_t^{\mathrm{d}} \geq 0$, and store it in an energy buffer $e_t \geq 0$, is then:

$$\underbrace{\frac{de_t}{dt}}_{\triangle\ \text{Energy buffer}} = \underbrace{\underbrace{p_t^{\mathrm{c}} \cdot \eta^{\mathrm{c}}}_{\text{Addition}} - \underbrace{p_t^{\mathrm{d}} / \eta^{\mathrm{d}}}_{\text{Removal}}}_{\text{Electric origin}} + \underbrace{\underbrace{p_t^{+}}_{\text{Addition}} - \underbrace{p_t^{-}}_{\text{Removal}}}_{\text{Exogenous origin}} . \tag{2.1}$$

This definition distinguishes *electricity storage* from the broader concept of *energy storage*. The latter can be defined as taking energy in whatever form it is available, converting it to whatever form is best for storage, and then reconverting it to whichever form is best for use [16]. Energy storage may thus, e.g., also refer to the storage of fuel in the natural gas grid or through coal piles, or to the potential energy stored in the gravitational field in the case of conventional hydro power plants.

Given nonzero energy losses, over time, electricity storage consumes more electricity than it generates. As such, it can not be labeled as generation asset. In fact, it is difficult to classify it as any type of power system asset. It can act as generator when discharging, as consumer when charging, and as energy buffer during storage. It also has similar characteristics to grid capacity as both have the ability to move power: storage in time and the grid in space. Therefore, the question arises whether storage needs to be treated as a separate class of power system assets.

However, it may be more relevant to ask whether electricity storage fundamentally differs from the other power system flexibility sources. This is not the case, as alternative means of flexibility can also be characterized by the combination of three functions introduced above for storage: all are able to provide downward and upward power adjustments by interacting with an energy buffer, thereby shifting energy in time (Fig. 2.1). Although they may differ based on technical and economic characteristics, no source is necessarily superior to another. Their value depends on the match between the required technical performance of the chosen application and their techno-economic characteristics [14]. Electricity storage is only one solution to deal with increasing flexibility needs, and alternative flexibility sources can be substitutes for certain applications, but complements for others, given the wide range and quantity of flexibility needs [16].

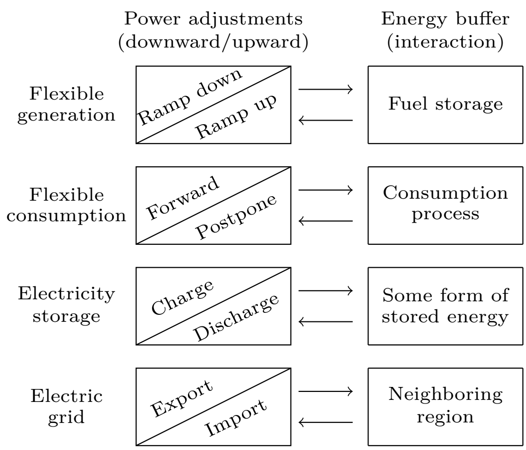


Figure 2.1: Overview of power system flexibility sources. All can be characterized by the same combination of three functions: providing downward power adjustments, accumulating energy, and providing upward power adjustments.

This does not mean that no more work is to be done by policy-makers on the regulation specifically for electricity storage. The unclear classification of storage resources may currently affect its operation and development through, e.g., eligibility of different types of players for storage ownership (i.e., can grid operators own storage resources, and if so, for which applications?), and grid tariffs (i.e., do storage resources have to pay tariffs for both generators and consumers, one of both, none, or a different type of tariff?).

2.2 Applications

Historically, electricity storage plants were considered as an alternative for investing in peak load generation. They were operated to charge during off-peak periods, thereby complementing inflexible base load generation, and discharge during on-peak periods. However, due to the liberalization process and the ongoing energy transition, distinct valorization paths for different applications of storage emerged [10, 25, 26, 27]. These can be categorized in energy, network, and reliability services, and they are discussed in detail in this section.

- Energy services include both arbitrage and portfolio management by market participants.
- Grid services include the provision of frequency control, voltage support, congestion management, and black-start capabilities to the TSO. The TSO is responsible for the stable operation and maintenance of the transmission system, and the interconnection with neighboring regions. In the future, some of these services will likely also be provided to the distribution system operator (DSO), which is responsible for the stable operation, maintenance, and development of the low and medium voltage grids. The provision of grid services to the DSO is quite innovative, as historically the goal of the distribution grid was merely to distribute electric energy delivered by the transmission level to consumers on the distribution level. In contrast to this rather passive character of the distribution system operation, an increased interest in the active operation of the distribution system can be observed to accommodate increasing levels of distributed energy sources, demand side management, and local storage.
- Reliability services include the support of reliability on both the local level and system level: the former through the provision of back-up, uninterruptible power supply (UPS), and power quality management, and the latter by providing firm capacity to contribute to generation adequacy.

The extent to which different storage technologies can technically provide these services depends on their technical characteristics, while the extent to which they are well-suited for these services depends on their technical and economic characteristics, and for some services on their location (i.e., transmission or distribution grid, and the physical location within those grids) as well.

2.2.1 Energy services

Arbitrage

Classic definitions of arbitrage denote making a riskless profit by simultaneously buying and selling a similar commodity with net zero investment [28]. However, any activity in which a player buys a commodity and sells a similar commodity, or one in which the former can be converted, at a higher price for profit can be referred to as arbitrage. This definition allows to include initial investments, does not require simultaneity of the purchase and sale, and furthermore does not restrict to a single commodity either [9].

This dissertation distinguishes four arbitrage types in electricity markets: intertemporal, interzonal, intermarket, and intercommodity arbitrage (Fig. 2.2). With intertemporal arbitrage, electricity price differences are captured over time (e.g., 03:00 am to 04:00 am vs. 05:00 am to 06:00 am), while interzonal arbitrage refers to the capturing of price spreads between adjacent market zones (e.g., Belgium vs. France (FR)). Intermarket arbitrage refers to the activity in which virtual bidders profit from price differences between different electricity markets (e.g., DA market vs. ID market) by making trades in the opposite direction to cancel outstanding positions. Finally, intercommodity arbitrage is based on price differences between fuel (e.g., gas) and electricity. These four basic arbitrage types can also be combined leading to hybrid types, e.g., intertemporal intermarket arbitrage is the capturing of electricity price spreads over time over different markets (e.g., DA market 03:00 am to 04:00 am vs. ID market 05:00 am to 06:00 am). Here, electricity storage arbitrage is defined to include intertemporal, intermarket, and intertemporal intermarket arbitrage.

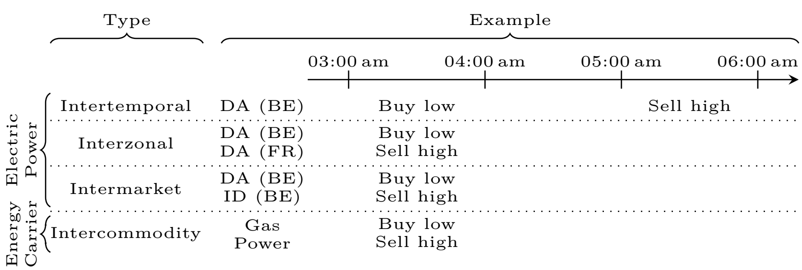


Figure 2.2: Arbitrage in electricity markets.

Aside from the operational flexibility of a storage plant, which is determined by its start-up and shut-down cost, minimum load requirements, ramp rates and cost, and minimum up and down times, four factors related to the combination of storage technology, storage sizing, and market parameters, are identified, that determine the profitability of electricity storage arbitrage.

1. The price spread between the buy price λ_t^{b} and sell price λ_t^{s}, and the cost due to energy losses if physical (dis)charge actions are required (i.e., with intertemporal and intertemporal intermarket arbitrage). The cost due to losses to arbitrage one unit of energy is calculated as $(1/\eta^{\mathrm{rt}} - 1) \cdot \lambda_t^{\mathrm{b}}$, with η^{rt} the roundtrip efficiency.

2. The price profile, and the (dis)charge duration. Two price profiles, containing identical prices but in a different order, result in different arbitrage profits in case the (dis)charge duration is limiting the optimal operation. E.g., a limited duration can cause the storage to be fully charged prematurely in times of consistent low prices, making it impossible to capture all present arbitrage opportunities.

3. The uncertainty and predictability of λ_t^{b} and λ_t^{s}. In the DA market, which is the most studied market for storage arbitrage, the uncertainty used to be much lower, and the predictability much higher, because of clear daily and weekly patterns of the system load and prices. However, the ongoing energy transition makes prices more uncertain as the historically clear patterns are becoming less obvious. This is even more challenging for ID prices and especially RT imbalance prices.

4. The price-effect, and the buy and sell volume. Typically, additional buy transactions increase λ_t^{b}, and additional sell transactions decrease λ_t^{s}. This price-effect is generally negligible for transactions that are small compared to the market size, but can be significant for large-scale storage transactions. Taking this into account results in a trade-off between the remaining price spread and transaction size.

Portfolio management

Portfolio management by market participants is performed at different timeframes, i.e., at the investment, scheduling, and operation phases, and covers generation investment deferral, intertemporal energy shifting, and capacity firming, respectively.

At the investment phase, storage may decrease the need for peak power plants that are usually only operated to meet the peak demand. It can decrease the need for such power plants by storing base load and RES generation in times of low demand and high RES generation, and by replacing peak generation in times of high demand and low RES generation. In addition, at future higher

RES targets the "fuel cost" of storage, which is related to the energy losses and the price at which energy is stored, decreases. This positive correlation between the decrease in operational cost of storage and the integration of RES presents an advantage compared to conventional power plants. The latter face fewer operational hours due to the merit-order effect of RES, and a decreasing profitability due to the lower electricity prices as a result of the close-to-zero marginal cost of RES.

At the scheduling phase, generators can maximize the value of generation by decoupling generation from grid injection, and consumers can minimize the cost of consumption by decoupling consumption from grid offtake. This is possible due to the intertemporal energy shifting ability of storage systems. Among others, generators can schedule the more inflexible base load and mid load generation technologies more efficiently through storage. The decoupling of consumption from grid offtake can be profitable for large consumers that directly participate in the wholesale markets, or for those that have a contract with their supplier through which they are sensitive to price fluctuations. In contrast, this would require more dynamic tariff structures or capacity-based tariffs for residential consumers instead of the current (quasi) fixed tariffs, or additional incentives for self-consumption in case of residential PV generation to avoid consumers using the grid as an unlimited and free storage resource.

At the operation phase, market participants can use storage for capacity firming purposes. Capacity firming may include both smoothing of generation or consumption output, resulting in less volatile power profiles, and the ability to follow predetermined output schedules to reduce imbalance positions in RT. The smoothing of output profiles can especially contribute to an efficient operation of conventional power plants because of their techno-economic operating constraints. Imbalance positions in RT are settled by the system operator imposing imbalance prices, which typically reflect the activation cost of reserves.

2.2.2 Grid services

Frequency control

To be able to satisfy the most important condition for a stable operation of the power system, being the instantaneous balance between generation and consumption of electric energy, system operators contract reserve capacity. These reserves are activated to compensate for unforeseen variations in generation and consumption. As these variations can occur on different time and duration scales, system operators hold different reserve categories. In the synchronous zone of the European network of transmission system operators for electricity (ENTSO-E), operating reserves are, besides the distinction between up and downward reserve, categorized in frequency containment reserve (FCR), frequency restoration reserve (FRR), and replacement reserve (RR).

FCR is activated automatically in a matter of seconds, in response to frequency deviations for the entire synchronous zone. FRR is either activated automatically (aFRR) or manually (mFRR), and restores the system frequency by restoring the balance in the control zone, thereby relieving the activated FCR. Its activation is triggered by the area control error (ACE), which is calculated as the difference between the scheduled and actual power interchange of a control area. Finally, RR can be used to relieve or support the activated FRR. Previously, FCR was referred to as primary reserve, aFRR was called secondary reserve, and mFRR and RR generally correspond to the concept of tertiary reserve (the former to fast tertiary reserve, the latter to slow tertiary reserve). If electricity storage plants meet the technical requirements to provide these reserve products, they can provide frequency control to the system operator [6, 29].

Voltage support

In order to keep the voltage level throughout the grid within the technical and contractual limits, the system operator contracts services to support the voltage. Voltage support in transmission grids is typically performed through reactive power control, i.e., generating and absorbing reactive power. In the distribution grid, due to their more resistive nature, a combination of active and reactive power control can be more effective. Next to the active power dispatch capabilities inherent to electricity storage, the grid interface of the storage system may also have reactive power control capabilities. In contrast to frequency control, the location largely determines whether storage systems can provide the appropriate amount of voltage support. Voltage has to be managed locally since reactive power is difficult to transport.

Congestion management

Congestion management indicates the ability to reduce flows on congested lines. Storage systems can provide this service if they are physically located in the grid-constrained areas. The provision of congestion management is thus, similar to voltage support, very location-specific. When considering a line that is often congested, the congestion issue could be solved by increasing the line rating, contracting flexible consumption capacity or installing generation capacity on the demand side of the congested line, or installing storage capacity on either side of the congested line. Contracting flexible consumption capacity would shift the demand from peak to off-peak periods, while installing generation capacity at the demand side of the congested line would reduce flows on the line, both relieving the issue. Storage capacity located at the demand side of the congested line could be charged during off-peak periods, and discharged during peak periods when the line would typically be constrained. Alternatively, storage capacity on the supply side of the congested line could be charged during peak periods when the line would typically be congested, and discharged when it is not. Providing such services may improve the utilization rate of the lines, and could also lead to investment deferral (or delay) in new lines or line upgrades. The latter may be especially valuable when such congestion situations occur in just a few hours or days per year, as the upgraded grid capacity would otherwise be strongly underutilized [15, 30].[1]

Black-start capabilities

In the event of a black-out, the system operator has to re-activate the system step-by-step. In order to do this, the system operator calls upon capacities that can start without external electric supply. Units with generation capabilities that have the ability to do this can provide the so-called black-start service to the system operator. In case an electricity storage plant meets the technical requirements to provide this service, and keeps a certain amount of energy stored in the buffer at all times, it can provide this black-start service. This includes an opportunity cost for the storage operator, since the reserved energy capacity cannot be used to provide other services.[2]

2.2.3 Reliability services

Local level

On the local level, consumers can use storage systems to either improve the quality of power used by its electric devices or to provide (or support) back-up in case of a disruption in the supply of electric energy. The former is referred to as power quality management, and is especially important to protect sensitive processes and loads of consumers. It is based on the ability of storage to buffer active power imbalances between demand and supply, and control reactive power

[1] Although this would also result in an underutilization of the storage system for solely this application, it may be more straightforward for storage than grid capacity to capture additional revenues by providing other services as well in combination with congestion management.

[2] However, in the case of PHS the effective head (i.e., elevation difference) is the lowest when the upper reservoir is almost empty, i.e., when the limit of the black-start energy content is reached. This lowers the opportunity cost for keeping a certain amount of energy stored.

through its grid interface. The latter increases the reliability of the supply of the consumer. Storage in combination with PV or wind can replace small-scale back-up generators (i.e., usually diesel), while storage as UPS can give a back-up generator (e.g., other storage system with a longer discharge duration, or diesel generator) the time to come online. In addition, distributed storage is often discussed to improve the energy-autonomy of prosumers, i.e., consumers who also operate distributed generation.

System level

Reliability services on the system level include having firm capacity available with the goal to ensure adequacy, i.e., installation of sufficient resources to meet the demand during peak and other times. For this purpose, capacity mechanisms are discussed and implemented throughout Europe, which provide revenue streams for firm capacity that are either alternative (e.g., the Belgian strategic reserve mechanism) or complementary (e.g., the UK capacity auction mechanism) to energy and balancing market revenue streams. These mechanisms provide a remuneration per unit of power [€/W], which is independent of the energy output but values the availability of capacity. If storage plants meet the technical requirements, and if they are allowed to, they can provide this service and as such be remunerated for their discharge power capacity.

2.2.4 Aggregation of applications

This multitude of applications makes electricity storage plants an interesting asset for a wide range of market participants. However, operating a storage plant to provide just one of these services might not result in a positive business case: profitability may require the aggregation of multiple applications. In addition, when considering multiple applications, the value of individual applications cannot simply be added as use for one application may interfere with use for another. Therefore, it is necessary to co-optimize the scheduling of the applications. Finally, applications cannot only be aggregated for a certain storage plant by one market participant, but also over multiple participants.

While multiple studies acknowledge the fact that such aggregation is critical in the value proposition for electricity storage, e.g., [30, 31, 32, 33, 34], the following statement from the well-known[3] THINK study [16] perfectly sets the scene for the work in Chapter 3 on the role and system value of storage considering a wide range of services, and the work in Chapter 6 and Chapter 7 on multi-application and multi-player storage operation, respectively:

[3] In the electricity storage community.

"To reveal the overall value of storage for the whole system, it is necessary to investigate the way to aggregate the benefits of storage for different services or even different actors that encompass both regulated and competitive activities. Today's challenges for the business model for electricity storage are (1) the aggregation of multiple services and (2) the maximization of multi-income streams."

2.3 Characteristics

Individual storage plants can be characterized by a set of technical and economic characteristics. Typically, they include the charge and discharge power rating and duration, energy storage capacity, losses and efficiency, calendar and cycle-life, volume and mass, and investment cost.[4]

2.3.1 Charge and discharge power rating and duration, and energy storage capacity

The (dis)charge power rating [W] represents the maximum amount of power during (dis)charge, while the energy storage capacity [J] refers to the amount of energy that can maximally be stored. In addition, the charge duration [s] typically expresses the time needed for the storage system to be fully charged at its power rating from being fully discharged, and vice versa for the discharge duration [s]. It depends on the ratio of the energy capacity to the power rating, and is therefore also referred to as the energy-to-power (E2P) ratio [s].

2.3.2 Losses and efficiency

The roundtrip efficiency [%] is defined as the ratio of the discharged electric energy to the electric energy that needs to be charged first for this discharge action to happen. It is strictly lower than 100 % because of energy losses. Losses in storage systems are incurred in multiple ways: during the conversion steps, during storage, and because of auxiliary systems. E.g., in a BES the first two sources of energy losses occur as follows. The grid's alternating current (AC) power is first converted to direct current (DC), after which the batteries convert the electric energy to chemical energy. Then, during storage, there may be continuous self-discharge. Finally, during discharging, the chemical energy is

[4]This list of characteristics is not meant to be exhaustive.

put back into the grid after it has been converted again to DC power and subsequently to AC power.

2.3.3 Lifetime

Storage plants have a limited lifetime, which is determined by the combination of their calendar life [s] and cycle-life [-]. It indicates the time or use after which the performance is decreased in such a way that it is not longer sufficient. The calendar life is the maximum time that the storage plant can be used, independent from use, while the cycle-life takes into account the deterioration of the energy storage subsystem due to use. The former can be considered the limiting factor in case of infrequent use, while it is the latter in case of frequent use. However, the statement “not sufficient anymore” is very application specific. E.g., for BES, the cycle-life is usually defined as the number of charge-discharge cycles before the remaining usable capacity falls below 80 % of the initial storage capacity due to wear. Nevertheless, since some applications value power rating more highly than energy storage capacity, this definition for lifetime may not always suffice. Furthermore, unclear lifetime figures may result from the fact that the lifetime of the power subsystem and energy storage subsystem may differ.

2.3.4 Volume and mass

The energy density and power density of a storage technology can be specified in terms of volume, i.e., [J/l] and [W/l], respectively, or mass, i.e., [J/kg] and [W/kg], respectively. These quantities can be used to estimate the size and mass of storage systems, and are important characteristics for applications requiring a small and light storage system. Additional space use and mass can be incurred because of the need for dedicated buildings, safety installations, and heating and cooling systems.

2.3.5 Investment cost

The initial investment in a storage facility comprises two main components: a cost per unit of power rating [€/W], and a cost per unit of energy storage capacity [€/J]. E.g., for PHS, the power subsystem cost comprises all costs related to pumps, turbines, motors, and generators, while the cost of the energy subsystem depends on reservoir capacities and the elevation difference.

2.4 Technologies

This section describes the general technological envelopes of electricity storage technologies often considered for grid integration, while providing links to the applications (Section 2.2) and techno-economic characteristics (Section 2.3) where appropriate. These technologies include PHS, compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES), BES, fuel cells, and P2G. For additional information on these technologies, the reader is referred to dedicated overview studies [30, 35, 36, 37, 38, 39, 40, 41, 42]. A summary and categorization is given in Table 2.1, based on own insights and inspired by the references indicated above.

2.4.1 Pumped-hydro storage

PHS represents over 99 % of the worldwide installed capacity of grid-connected electricity storage, with currently 162 GW of installed capacity [43]. It is a mature technology, with limited energy losses (roundtrip efficiency of 65-85 %), and a long lifetime (40-60 years, and tens of thousands of cycles). In a PHS plant, an electromotor consumes electricity to pump water from a lower reservoir to an upper reservoir, storing energy. Electricity is generated again by releasing the water to flow from the upper to the lower reservoir, using a turbine to drive a generator [44]. The energy capacity is a function of the elevation difference and volumetric capacity of the water reservoirs. PHS plants are employed to provide a wide range of services, from grid services to the system operator (e.g., frequency control, black-start service), to energy services to the market (i.e., arbitrage) and generation portfolios (i.e., portfolio management), and reliability services to the system (i.e., firm capacity).

In the industrialized world, most of the obvious locations may already have been captured. Converting some of the current hydro power plants to PHS plants is considered an attractive option to increase the available storage capacity [45]. In addition, as a large share of the existing PHS capacity was built decades ago, equipping it with new and more efficient technology presents significant potential to increase and improve current PHS capacity. Due to their geographical requirements, both hydro and PHS plants are typically found far from population centers. Individual PHS plants have power ratings of up to several GW during a few hours up to a few days. Improved PHS technologies are developed, to increase the flexibility in terms of (1) services, and (2) land use and location. Classically, in pumping mode the power output of a pump-turbine set is fixed, i.e., inflexible. In contrast, variable speed technologies enable more flexibility and improve the dynamic behavior. On the other hand, using the sea as a "reservoir" or using underground reservoirs can minimize land use and environmental impact, and open up new suitable locations [18].

2.4.2 Compressed air energy storage

Although CAES is one of the most important storage technologies in terms of installed capacity next to PHS, only two major plants are currently operational, i.e., the 321 MW Huntorf plant in Germany (DE) and the 110 MW MacIntosh plant in the US [18]. In a CAES plant, air is compressed by an electromotor driving a compressor, and energy is stored due to the increased pressure. This also increases the temperature, with the heat representing part of the energy converted in the process. If after pressurizing and before injection in the reservoir, the compressed air is cooled down without heat storage, the thermal energy is lost and the roundtrip efficiency decreases [36]. To make up for the heat loss, a fuel, typically natural gas, is used to reheat before and during expansion of the compressed air. This expansion drives a turbine to generate electricity again. The energy capacity is related to the volume and rated pressure of the reservoir.

Typically, natural storage reservoirs are used, including salt caverns, former mines, and former natural gas sites. Consequently, the application of this technology is, similar to PHS, limited due to geographical requirements. E.g., both the Huntorf and MacIntosh plants use salt caverns as reservoirs. CAES system ratings are in the range of hundreds of MW for a few hours up to a day. CAES is competitive with PHS in terms of lifetime, sizing, applications, and storage duration, and, similar to PHS, it is characterized by low energy subsystem investment costs in case of favorable geographical conditions.

New developments in CAES technology aim to improve the roundtrip efficiency and increase the flexibility in siting. The efficiency of conventional diabatic CAES technology (40-60 %) can be improved to about 70 % by storing heat from the compression in thermal storage systems, and releasing it again before and during expansion to eliminate the need for additional fuel, i.e., adiabatic CAES technology. In addition, artificial pressure tanks can be manufactured for aboveground reservoirs to circumvent the geographical requirements. This also enables the development of small-scale CAES plants [16, 46].

2.4.3 Flywheels

Flywheels have known limited success, with about 45 MW of capacity installed worldwide. Electricity is consumed by an electromotor to accelerate a rotor to very high speeds (up to 50 000 rpm), storing kinetic energy. The system is discharged by using this energy to drive a generator, thereby reducing the flywheel's speed. The energy content depends on the rotational speed and the moment of inertia of the spinning mass. Self-discharge is typically high, due to the presence of friction-related losses [36, 40]. A thick steel containment generally surrounds the flywheel to improve safety and performance. It stops or slows down fractured parts in case of an incident, preventing or reducing injury and damage, and reduces friction-related losses if placed under vacuum or if filled with a low-friction gas, e.g., helium [30].

The advantages of flywheels include high power density, long lifetime (15-20 years, and hundreds of thousands to millions of cycles), a high roundtrip efficiency of 80-95 %, and very fast response times. The storage capacity of individual flywheels is limited, with typical capacities between 0.5 kWh and 10 kWh [25]. Therefore, numerous flywheels are installed together to increase the total capacity of a flywheel system. Flywheels are typically designed for a (dis)charge duration of a few seconds up to an hour, and have a low energy density. Consequently, they are used in applications for which a high number of cycles is expected, and for which high power is more valuable than high energy capacity. E.g., a 20 MW flywheel plant, comprising 200 flywheels of 100 kW, is in operation in the US (Stephentown, New York) since 2011 to provide primary frequency control to the system operator [30, 47]. Other well-known applications of flywheels are power quality management and UPS [16, 35].

2.4.4 Supercapacitors

Only limited grid-connected supercapacitor capacity is operational today. They are often referred to as "supercaps", and store energy in the electric field between the two electrodes of a capacitor [39]. Similar to batteries, supercaps contain two electrodes, an electrolyte ionically connecting both, and a permeable membrane allowing ion transfer. The energy capacity is related to the electrode surface area and voltage, and is inversely correlated to the distance between the electrodes [38]. In contrast to batteries, not a chemical reaction but an electrostatic action takes place. This makes the (dis)charge process easily reversible without significant degradation, resulting in a very high cycle-life in the same order of magnitude as flywheels, and a calendar life of about 20 years. The efficiency is high as well at 85-95 %, as is the power density, and they have a very fast response time. Grid application necessitates putting a number of capacitors in series since the voltage of a single basic unit is limited to a few Volt. The most commonly cited limiting factors are the high self-discharge rate, high cost of the energy storage subsystem, and low energy density [38, 39], which most likely limit the use of supercaps to short (dis)charge duration applications, similar to flywheels. Often cited applications include primary frequency control, voltage support, power quality management, and UPS [16, 35, 39].

2.4.5 Superconducting magnetic energy storage

Similar to supercaps, few SMES systems are currently in operation in the grid. With SMES, energy is stored in the magnetic field of a direct current flowing in a superconducting coil. The current magnitude increases during charging and decreases during discharging, with the energy capacity being correlated to the current rating and the inductance of the coil. To maintain superconductivity, very low, i.e., cryogenic, temperatures are required [38, 48]. The complexity of the cooling system and the related cost, and the cost of the energy storage subsystem, currently limit SMES to high power applications, offering MW ratings for just a few seconds. The response time and power density are very high, as is the lifetime (similar to supercaps), with the coils not degrading with age or use. Well-suited applications thus also include those requiring frequent cycling, as with flywheels and supercaps. Although the efficiency is very high as well at more than 95 %, which is among the highest values of all storage technologies, the cooling system leads to additional losses if cycling is not frequent. Another often cited disadvantage includes the impact of the magnetic field [39, 41].

2.4.6 Battery energy storage

Batteries consist of two electrodes, an electrolyte, and a permeable membrane. When discharging, electrons flow through an external circuit from the negative to the positive electrode, creating an electrical current from the positive to the negative terminal, and the other way around during charging by applying an external voltage over the electrodes, enabling (reversible) chemical reactions. Simultaneously, ions flow via the electrolyte between the electrodes to maintain charge balance. With BES, power ratings and energy capacity are typically closely related, limiting the flexibility in sizing. In addition, the cycle-life of BES is typically a limiting factor, with in general order of magnitudes of a few thousand cycles. Therefore, when stating that a certain chemistry has a good cycle-life, this has to be considered in the context of BES. Furthermore, BES is typically characterized by very fast response times.

BES is considered to be very versatile and scalable, from kW to multi-MW systems, because of the modularity of battery cells and the wide range of chemistries. This section focuses on the chemistries that are most often considered for power system applications. Lead-acid (Pb-acid) is a well-known technology and has been used the longest in power systems, with proven applicability, but with limited deployment in terms of installed capacity. Until recently, the less mature sodium-sulfur (NaS) was by far the most commonly used technology with about 530 MW deployed worldwide [49], but the more recent lithium-ion (Li-ion) technology has caught up due to the large amount of projects developed over the past few years as a result of its rapidly decreasing cost and increasing performance [14, 30, 50]. In addition, flow batteries are discussed as well as they have the potential for longer term storage and decoupled power and energy ratings.

Lead-acid

Pb-acid is a well-known and relatively inexpensive technology, operating at normal atmospheric temperatures. However, its energy and power densities, and cycle-life (up to a thousand cycles), are low, but roundtrip efficiency is good at 70-85 %. Calendar life ranges from 5 to 15 years. In addition, because of the lead, recycling, which is (luckily) very common, is needed to avoid a high environmental impact [14, 41]. Common applications are those requiring power for short periods of time, and limited cycles, e.g., power quality management, black-start service, and UPS [16, 35].

Sodium-sulfur

NaS is a kind of high temperature chemistry that uses low cost, but somewhat hazardous, materials. This chemistry offers good roundtrip efficiencies of 75-90 %, and a good energy density. Calendar and cycle-life are good as well at 10-15 years and a few thousand cycles. However, the heating system represents additional costs and losses. NaS is operated worldwide, and is used to provide grid services such as frequency control, or multi-hour energy services such as portfolio management (e.g., optimizing the operation of wind power plants) not requiring very frequent cycling. Typically, installed NaS systems have power ratings from 1 MW up to 50 MW, with 6-7 h of storage capacity [14, 39, 49].

Lithium-ion

Li-ion refers to a class of BES in which Li-ions move between the electrodes, operating at temperatures within the normal atmospheric range. Depending on the active materials, different trade-offs of energy density, power density, and cost are available. In general, Li-ion BES have a high roundtrip efficiency (85-95 %), power density, and energy density, but a significant energy subsystem investment cost. However, prices are decreasing quickly because of (1) economies of scale linked to mass production, and (2) learning effects linked to the deployment of electric vehicles [50]. Lifetime is good as well, in the same order of magnitude as NaS. Li-ion systems have been demonstrated up to a few tens of MW with 15 min up to about 10 h of storage capacity [14, 30]. This makes them suitable for both power-based applications such as frequency control, and energy-based applications such as arbitrage and portfolio management in case cycling is not too frequent, given their limited cycle-life compared to, e.g., PHS.

Flow batteries

Flow batteries are based on a similar electrochemical process as conventional BES, but have liquid electrolytes with dissolved active materials stored in two separate tanks, which are pumped to the electrodes during operation. This leads to lower self-discharge and the decoupling of power vs. energy sizing, with the size of the tanks defining the energy capacity. This makes flow batteries potentially more suitable for mid-to-long term storage compared to other BES technologies [30]. The cycle-life, with an order of magnitude of ten thousand cycles, and scalability, are very high, but the maturity is low (demonstration or pre-commercial phase). Other drawbacks are the low energy density and high complexity because of pumps and control systems. The investment cost for the energy storage subsystem is significant as well, and flow batteries are characterized by a good efficiency and calendar life of 70-85 % and 10-20 years, respectively. Typical flow battery system ratings range from hundreds of kW to tens of MW for multiple hours. Most commonly used chemistries include vanadium-vanadium (Va-Va) and zinc-bromine (Zn-Br) [14, 18, 25]. Due to their scalability, flexible sizing, and long lifetime, flow batteries are expected to become a BES technology that is well-suited to provide longer duration energy services, at least in case sufficient space is available (due to their low energy density), once they become mature.

2.4.7 Fuel cells

Just like BES, fuel cells are composed of individual electrochemical cells. In contrast to BES, a fuel is used. Common fuels include hydrogen, methanol, and natural gas. Fuel cells can discharge for as long as this fuel is supplied. Typically, oxygen, taken from the atmosphere, is used as oxidant. Fuel cells are categorized by the kind of electrolyte and fuel used, with common types including proton exchange membrane fuel cells, direct methanol fuel cells, phosphoric acid fuel cells, alkaline fuel cells, solid oxide fuel cells, and molten carbonate fuel cells [51]. In a unidirectional use of fuel cells, they function as generator given the input of fuel, not as electricity storage system. For the latter, unidirectional fuel cells can be combined with P2G technology. Some fuel cell technologies can be directly used in a bidirectional way, functioning as both generator and consumer: a first chemical and electricity are consumed to produce a second chemical, and the second chemical is consumed to generate electricity and produce the first chemical [35].

Often cited advantages include a fuel cell's flexible sizing, scalability (from a kW to MW scale), and possibility for large energy capacities, while disadvantages include the system's roundtrip efficiency (lower than 50 %), investment cost, and the need for a complementary technology, e.g., electrolyzer, for a bidirectional functioning. In addition, common values for the cycle-life are limited to a few thousand cycles, and for the calendar life to 5-15 years. Today, only very limited fuel cell capacity is grid-connected due to its limited maturity.

2.4.8 Power-to-gas

P2G technology stores energy in a chemical form, by converting electricity to hydrogen and possibly to methane. In charge mode, electricity is consumed in the electrolysis process by splitting water into hydrogen and oxygen. The hydrogen can then be stored as such, or combined with carbon dioxide in a methanation process to form methane, which is then stored. Since hydrogen can only be injected to a limited amount into the existing natural gas grid, the methanation step has the advantage that the storage capacity becomes, at least compared to other electricity storage technologies, extremely large. In second instance, storage capacities could even be increased when taking new reservoirs, e.g., depleted oil fields, into account. The disadvantage of the methanation step is the decreased efficiency. To convert the produced gas back to electricity in discharge mode, it is used as fuel for a gas turbine or fuel cell. Often cited roundtrip efficiencies range from 25 % to 50 % [52].

P2G is currently still in the demonstration phase with projects of several kW up to 6 MW of installed electrolyzer capacity. The modular configuration of electrolyzers, composed of multiple small electrolyzer cells, allows for future P2G systems ranging from several kW up to a GW. Although current roundtrip efficiencies are very low, P2G may offer a high potential, since it is considered to be the sole electricity storage technology that offers seasonal storage capabilities [53, 54].[5]

[5] While PHS is usually considered to be a storage technology with (dis)charge durations of several hours up to a few days, countries such as Norway and Switzerland may accommodate PHS plants with much longer durations as well.

Table 2.1: Summary and categorization of electricity storage technologies often considered for grid integration.

Type	Technology	Buffer	Carrier	Conversion technology	Advantages	Disadvantages
Mechanical	PHS	Gravitational field	Water	Electromotor-generator, pump-turbine	Energy subsystem cost, efficiency, lifetime, maturity, storage capacity	Energy density, environmental impact, geographical conditions, lead times
	CAES	Pressure (and heat)	Air	Electromotor-generator, compressor-turbine	Energy subsystem cost, lifetime, storage capacity	Energy density, efficiency, geographical conditions, limited demonstration
	Flywheels	Kinetic energy	Flywheel	Electromotor-generator, flywheel	Efficiency, lifetime, power density, response time, scalability	Energy density, self-discharge, storage capacity
Electrical	Supercaps	Electric field	Capacitor	Power-electronic converter	Efficiency, lifetime, power density, response time, scalability	Energy density, energy subsystem cost, maturity, self-discharge, storage capacity
	SMES	Magnetic field	Coil	Power-electronic converter	Efficiency, lifetime, power density, response time	Energy density, energy subsystem cost, environmental impact, complexity, maturity
Electrochemical	BES	Chemical potential	Active materials (electrodes)	Power-electronic converter	Efficiency, scalability, energy density, learning effects, mass production, response time	Energy subsystem cost, environmental impact, inflexible sizing, Lifetime, safety
	Fuel cells	Chemical potential	Active materials (fuel)	Power-electronic converter, electrochemical reactor	Flexible sizing, scalability, storage capacity	Efficiency, limited demonstration, need for second technology
Chemical	P2G	Chemical potential	Active materials (hydrogen, methane)	Electrochemical (and chemical) reactor	Energy subsystem cost, existing infrastructure, storage capacity, scalability, versatility	Efficiency, limited demonstration, need for second technology

Chapter 3

Role of electricity storage

Evaluating the role of electricity storage by considering short-term operation in long-term planning

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The first author is the main author of this article. The contributions of the first author include the co-development of the literature study, the co-development of the model, the software implementation in MATLAB and GAMS, the analysis and interpretation of the results, and the writing of the manuscript. The model is inspired by the work of the second author, and the work is done under supervision of the third and fourth author. A preliminary version of this article is published as a DIW Berlin Discussion Paper [56].

Abstract:

Short-term operating requirements and constraints in power systems are becoming increasingly important with the greater flexibility needed due to the integration of variable renewables. However, large problem sizes and computational barriers have limited the extent to which they are included in long-term planning models. Our objective is to understand the role of electricity storage in future renewable-based systems by including an accurate

representation of short-term operation with high temporal detail within a long-term planning framework. Specifically, we discuss the development of a long-term investment model including a continuous relaxation of the technology-clustered formulation of the short-term unit commitment problem, including detailed operating reserve sizing and supply. This model is solved for a full year, and is applied to a test system with system load and renewable generation characteristics from the Belgian power system in a greenfield setting, i.e., assuming no pre-existing capacities, to analyze the role of storage at different renewable penetration levels. Both pumped-hydro storage and battery energy storage are considered, and their role in providing energy services and frequency control is investigated. We derive broadly applicable conclusions on the benefits and role of electricity storage to motivate why it may be built and operated. Results show that, in general, the integration of storage resources decreases total system cost, partially replaces flexible power plants, facilitates the integration of renewable energy sources, and allows inflexible technologies to perform better.

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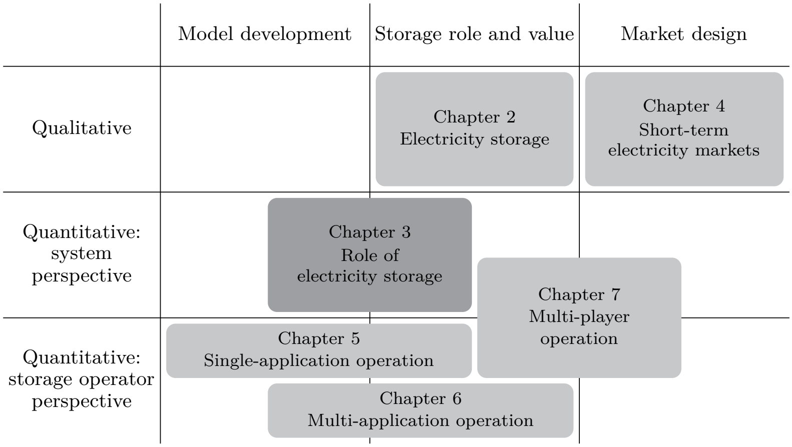

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3.1 Introduction

3.1.1 Motivation

Electricity storage refers to systems, bidirectionally coupled with the power system, which buffer energy. The energy buffer can be implemented based on a variety of physical principles: energy stored as thermal, chemical, electrochemical, kinetic, or potential energy, or in the electromagnetic field [13]. Although PHS is currently the most installed storage technology with $\geq 99\,\%$ of global capacity, and significant potential for new PHS capacity may still be present [3, 57], cost decreases and technological advancements are making BES increasingly competitive. The storage of electricity is expected to play an important role in the transition to power systems with high shares of variable RES in the generation mix [58]. Variable RES technologies, i.e., wind turbines and PV systems, are characterized by their dependency on weather conditions, which lead to expected power variations and unexpected forecast errors, and as such generally increase the variability in the system. This variability can be dealt with by flexibility, which indicates the ability to provide power adjustments to keep the system balanced at different time scales. Flexibility can be provided by flexible supply, flexible demand, and storage, which can also be activated in neighboring regions through the grid [9].

This chapter studies the role of storage in future RES-based systems by means of a long-term investment model for generation and storage capacity, commonly referred to as a generation expansion planning (GEP) model. Conventional GEP models typically include a simplified representation of short-term system operation and its costs, through low temporal and operational detail. However, the ongoing integration of variable RES makes short-term system operation increasingly important to consider in detail in long-term system planning [29, 59]. It is only by considering a high level of temporal and operational detail that accurate insights can be obtained in the role of storage.

3.1.2 Literature review

Including temporal and operational detail in generation expansion planning

Four approaches can be identified for the temporal detail, each with a different trade-off between computation time and the extent to which short-term operation can be accurately considered. First, planners can use a load duration curve (LDC), or residual LDC (RLDC) when considering variable RES. This approach neglects the chronology of the generation and consumption balance, and thus does not allow to include intertemporal links and related costs (i.e., start-up and shut-down costs, minimum up and down times, ramp rates and costs, and energy storage buffer dynamics) [22]. Second, some GEP models represent the seasonal, weekly, and daily variability within a year by a limited number of time slices [60]. The value for any time slice for the RES generation and system load corresponds to the average value in the period considered in the time slice. While this may not result in large approximation errors with low shares of variable RES, with high shares of variable RES this underestimates the variability of the residual load, and undervalues flexible technologies compared to inflexible technologies [61, 62]. Third, GEP models can include a set of representative periods (e.g., a few days or weeks), chosen such that their RLDC approaches the RLDC of the entire year [22, 61]. The disadvantage is that the selection of representative periods may be difficult to justify, and that it is difficult to represent all variability in the system in a limited set of periods, thereby leading to inaccuracies [60]. Fourth, the most accurate approach, but also the most computationally intensive one, is the use of hourly time steps for the entire year. While this is common practice in short-term models, it is not for long-term models due to the increase in problem size.

The operational detail determines how accurately technical constraints on the power plant level (i.e., commitment decisions, generation limits, ramp rates, minimum up and down times, energy storage buffer dynamics) and system level (i.e., power balance, reserve balance) are taken into account. High operational detail is typically present in short-term power system models, i.e., UC and economic dispatch models, which can assess the impact of RES integration on system operation, and thus on the scheduling of power plants. They are generally used to focus on issues related to flexibility adequacy, i.e., the short-term ability to keep the system balanced. In contrast, long-term power system models, i.e., investment and GEP models, can assess the impact of RES integration on system planning, and thus on the generation mix. They are generally used to focus on issues related to system adequacy, i.e., the ability to meet peak demand. To keep computation efforts within limits, they typically do not consider the same level of operational detail as short-term models [63]. Historically, low operational detail could be present in GEP models without large approximation errors [64, 65]. However, this is not the case with the greater flexibility required due to the integration of variable RES: short-term operation becomes increasingly important to consider in long-term planning [66]. Not considering this leads to an underestimation of the need for and value of flexibility [29, 59]. In this regard, two approaches to increase operational detail in GEP can be identified [61]. In the first approach, the investment and operation problem are considered separately and sequentially, i.e., the results of the investment problem are ex post used as input for the operation problem. This is referred to as the so-called soft-linking of both problems, which can also be solved iteratively [67]. In the second approach, the operation problem with high operational detail and the investment problem are solved together and simultaneously.

Role of electricity storage in power systems

The role and value of storage has already been studied in the existing literature with varying levels of capacity expansion opportunities and temporal and operational detail.

First, many studies have examined the benefits of storage on system operation by considering predetermined generation and storage portfolios, not allowing for endogenous capacity expansions (e.g., [68, 69, 70, 71, 72, 73]). This is typically done by comparing results, in terms of operational costs, dispatch schedules, or RES curtailment, of a reference case without storage with one or multiple cases including storage.

Second, others focus exclusively on the storage sizing problem given exogenously-defined generation portfolios. Ref. [74] optimizes storage investments considering the residual load and using a simplified representation of short-term operation, with storage as a way to compensate excess RES generation. In [75] storage sizing is based on the system's variability, while in [76] it is based on the system's uncertainty, and [77, 78, 79] consider both to determine storage requirements over different time scales.

Third, the final category of studies co-optimizes storage with generation investments. Ref. [80] uses some form of RLDC method, neglecting the chronology of the required power balance over time, thereby not capturing intertemporal links and related costs. Ref. [81] does not consider any operational detail in the planning of storage, generation, and grid capacity. Ref. [82] considers an hourly power balance, subject to operational constraints, but does not consider reserve requirements. In [83], a detailed combined investment and dispatch model is proposed, which neglects commitment decisions, minimum load levels, and minimum up and down times, but aims to compensate this shortcoming through ramping penalties. Ref. [84] includes a detailed representation of system operation, but considers exogenous investments in RES and endogenous investments in selected conventional generation technologies and CAES, and includes simplified reserve modeling. In [85] and [34, 86], a detailed short-term operation is included, but only a limited number of representative days is considered. This may lead to inaccurate representations of consumption and RES generation variations, and may not fully capture the added value of the ability of mid-to-long-term storage to shift energy between more distant, or longer, periods of time. Finally, [87] includes a lot of operational detail, but only considers four representative weeks, and assumes fixed E2P ratios for storage, making it difficult to gain insight in optimal storage sizing for energy-related vs. power-related services. In addition, whereas we focus on RES generation targets, [87] focuses on CO_2 emission goals.

3.1.3 Scope and contributions

This chapter's scope and contribution is the illustration of the role of electricity storage in future RES-based systems by including an accurate representation of short-term system operation within a long-term planning framework.

We first discuss the development of a combined, and simultaneously solved, long-term investment and short-term operation model with high temporal and operational detail. We consider hourly periods for a full year, and consider high operational detail in line with what is considered in a short-term power system model. In order to be able to solve numerically for meaningful optimization horizons, short-term operation is modeled through a continuously-relaxed and technology-clustered approximation of the conventional mixed-integer plant-level UC problem. This model is able to capture the increasing impact of flexibility needs in both the close-to-RT scheduling phase (i.e., energy market) and RT operation phase (i.e., reserve market), following the ongoing integration of variable RES, and includes a detailed representation of the flexibility supply by both generation and storage technologies. The representation of operating reserves is unparalled in that it includes detailed exogenous and endogenous reserve sizing, and periodical (i.e., for multiple hourly periods) reserve allocation to providers, in line with the market design in Europe.

Second, we apply this model to a test system with system load and RES generation characteristics from the Belgian power system in a greenfield setting, i.e., assuming no pre-existing capacities. We do not aim to determine likely deployment scenarios or address optimal pathways towards the future, but to derive general conclusions on the benefits and role of storage at different RES penetration levels, and to gain insight in the interdependency between flexibility options.[1] Both PHS and BES are considered, and their role in providing energy services and frequency control is investigated. We consider different storage scenarios with regard to the available natural potential for PHS and decreasing cost of the energy storage subsystem of BES.

[1] Nevertheless, the developed model can be used for a wide range of other studies as well, such as analyses on the value of RES in different flexibility scenarios, the impact of policy decisions and market design rules, and the impact of technological breakthroughs.

3.2 Methodology

The developed model is a partial equilibrium model, focusing solely on the electricity sector. It decides on the investments in and dispatch of generation and storage capacity to meet the demand for energy and reserves at lowest total system cost, while respecting detailed short-term operation constraints, and reaching increasing RES targets. Results from such a system perspective approach may serve as a proxy for the outcome in a vertically integrated environment, an unbundled environment with a centralized electricity pool model (e.g., the PJM market), or a liberalized market with bilateral and exchange-based trading (e.g., the European market) assuming perfect competition [88].

All technologies are defined as either injection or offtake technologies. In the developed model injection technologies include dispatchable and intermittent generation, and storage discharging. In real power systems they also include import from adjacent markets through interconnection capacity, and the postponing of flexible consumption. Offtake technologies include storage charging, but in real systems they also include export to adjacent markets, and the forwarding of flexible consumption.

3.2.1 Continuously-relaxed and technology-clustered UC formulation

The mixed-integer plant-level UC problem alone is already computationally challenging to solve for significant optimization horizons, even in its deterministic form and without grid representation. This is in part due to its many and elaborate techno-economic constraints, but especially because of the many commitment decisions represented by binary variables for each unit for each time step. Therefore, a more computational-friendly formulation of the UC problem needs to be included as a subproblem next to the investment problem within a GEP model with high temporal detail. To reduce problem size and facilitate manageable computation times, we couple a continuous relaxation of the technology-clustered formulation of the UC problem to the investment problem.[2]

[2] Although this continuously-relaxed and technology-clustered approximation should not be used to analyze actual system operation, it is valuable to include short-term operation in long-term planning.

Technology-clustered UC formulation

A technology-clustered formulation combines identical or similar units into clusters, which assumes nonbinding transmission constraints, i.e., a copper plate, and identical techno-economic characteristics of units within a cluster. The latter introduces approximation errors for existing capacity, as for this capacity differences among units exist due to project-specific elements, but not for new capacity, as for this capacity it is common practice in planning studies to use generalized data. The use of technology-generalized data thus impacts the results in long-term GEP with capacity legacy, but does not introduce errors compared to plant-level formulations in long-term greenfield GEP [22, 63, 89]. Approximation errors occur because of the inherent mathematical difference between plant-level and clustered formulations. However, [22, 89] show that a clustered formulation only results in minimal errors (i.e., near or below 1 %) while needing significantly less computation time (i.e., up to 2 000 times), which is also confirmed by [90], thereby justifying the use of a technology-clustered UC formulation in GEP models.

Clustering reduces the problem size in two ways. First, the large set of binary variables representing the commitment decision of individual units (i.e., 0 or 1) is replaced by a smaller set of integer variables that represent the commitment decision of a cluster (i.e., from 0 to the number of units in the cluster). Second, clustering also reduces the number of continuous equations and variables, as all decisions except a unit's commitment (i.e., power output, reserve provision) apply to the small number of clusters rather than the large set of individual units. Commitment decisions are still captured at the unit level.

Continuously-relaxed UC formulation

In addition, to include the UC problem in an investment framework, computation times are further reduced by replacing the integer commitment variables by linear commitment variables. Such a linearized technology-clustered formulation of the short-term UC problem coupled to the long-term investment problem has already been successfully used in [29, 91]. Of all short-term operating constraints, [91] found that relaxing integers provides the best accuracy vs. computation time trade-off for power system planning purposes, and concludes that a continuously-relaxed and technology-clustered formulation is strongly advised for GEP studies focusing on flexibility.

3.2.2 Objective function

The objective of the developed model is to determine the generation and storage mix, output schedules, and reserve provision, such that the demand for energy and reserve capacity is met at the lowest total system cost over the full optimization horizon $|\mathbb{H}| \cdot T^{\mathrm{h}}$ (3.1). The total system cost consists of the following costs for all injection and offtake technologies: the power-related investment cost, fixed operation and maintenance (O&M) cost, fuel cost, variable O&M cost, ramp cost, start-up cost, and shut-down cost; the following additional costs for all storage technologies: the energy-related investment cost, and depreciation cost following excessive storage cycling; and finally the load shedding cost in case of insufficient available supply, and curtailment cost in case of excess renewable generation:

$$
\begin{aligned}
\min \quad & \Bigg[\sum_{i \in \mathbb{I}} \Big[(C_i^{\mathrm{inv,inj}} + C_i^{\mathrm{fom,inj}}) \cdot p_i^{\mathrm{inst,inj}} + \sum_{h \in \mathbb{H}} \big[(C_i^{\mathrm{fuel,inj}} + C_i^{\mathrm{vom,inj}}) \cdot p_{i,h}^{\mathrm{inj}} \cdot T^{\mathrm{h}} \\
& \quad + C_i^{\mathrm{ra,inj}} \cdot (p_{i,h}^{\mathrm{ru,inj}} + p_{i,h}^{\mathrm{rd,inj}}) + C_i^{\mathrm{su,inj}} \cdot p_{i,h}^{\mathrm{su,inj}} + C_i^{\mathrm{sd,inj}} \cdot p_{i,h}^{\mathrm{sd,inj}} \big] \Big] \\
& + \sum_{o \in \mathbb{O}} \Big[(C_o^{\mathrm{inv,off}} + C_o^{\mathrm{fom,off}}) \cdot p_o^{\mathrm{inst,off}} + \sum_{h \in \mathbb{H}} \big[(C_o^{\mathrm{fuel,off}} + C_o^{\mathrm{vom,off}}) \cdot p_{o,h}^{\mathrm{off}} \cdot T^{\mathrm{h}} \\
& \quad + C_o^{\mathrm{ra,off}} \cdot (p_{o,h}^{\mathrm{ru,off}} + p_{o,h}^{\mathrm{rd,off}}) + C_o^{\mathrm{su,off}} \cdot p_{o,h}^{\mathrm{su,off}} + C_o^{\mathrm{sd,off}} \cdot p_{o,h}^{\mathrm{sd,off}} \big] \Big] \\
& + \sum_{s \in \mathbb{S}} (C_s^{\mathrm{inv,e}} \cdot e_s^{\mathrm{inst}}) + \sum_{h \in \mathbb{H}} \Big(C^{\mathrm{ls}} \cdot p_h^{\mathrm{ls}} + \sum_{i \in \mathbb{III}} C_i^{\mathrm{l}} \cdot p_{i,h}^{\mathrm{l,inj}} \Big) \Bigg] / (|\mathbb{H}| \cdot T^{\mathrm{h}}) \\
& + \sum_{s \in \mathbb{S}} c_s^{\mathrm{cyc}}.
\end{aligned} \tag{3.1}
$$

3.2.3 Power system constraints

Three requirements are considered on the system level. First, an hourly power balance between scheduled generation and consumption is included, i.e., the energy market-clearing constraint (3.2), ensuring that the expected variability in the system is dealt with. Second, an hourly balance between the demand for and supply of reserve capacity is included, i.e., the reserve market-clearing constraint (3.3), ensuring that the unexpected variability in the system is dealt with. ENTSO-E categorizes reserves into three groups. FCR, i.e., primary control, is activated automatically to stabilize the frequency in a matter of seconds. FRR is either activated automatically (aFRR), i.e., secondary control, or manually (mFRR), i.e., fast tertiary control, and restores the system frequency by restoring the balance in the control zone, thereby relieving the activated FCR. Finally, RR, i.e., slow tertiary control, can be used to support or relieve the activated FRR [29]. In the developed model the demand for reserves includes an exogenously-determined component in line with current system imbalances (SIs), and an endogenously-determined component to deal with additional SI volumes due to forecast errors of increasing levels of RES generation. The latter is endogenously-determined as it depends on the installed RES capacity, which is decided upon during the optimization and increases with the RES generation target. The sizing of both components is discussed in Section 3.2.7. Third, a system-wide RES generation target is imposed to ensure that a predefined share of the consumption is covered by RES (3.4):

$$\sum_{i\in\mathbb{I}} p^{\text{inj}}_{i,h} - \sum_{o\in\mathbb{O}} p^{\text{off}}_{o,h} = D_h - p^{\text{ls}}_h, \qquad \forall\, h \in \mathbb{H}, \tag{3.2}$$

$$\sum_{i\in\mathbb{I}} r^{\text{inj}}_{r,i,h} + \sum_{o\in\mathbb{O}} r^{\text{off}}_{r,o,h} = R^{\text{ex}}_r + \sum_{i\in\mathbb{III}} (R^{\text{en}}_{r,i} \cdot p^{\text{inst,inj}}_i), \quad \forall\, r \in \mathbb{R}, h \in \mathbb{H}, \tag{3.3}$$

$$\sum_{h\in\mathbb{H}} \sum_{i\in\mathbb{III}} p^{\text{inj}}_{i,h} \geq S^{\text{res}} \cdot \sum_{h\in\mathbb{H}} D_h. \tag{3.4}$$

3.2.4 Dispatchable injection and offtake constraints

Flexibility is provided through cycling, which can be defined as changing the output by starting up, shutting down, or ramping up and down. Techno-economic constraints that limit this cycling include commitment decisions, start-up and shut-down costs, minimum and maximum output levels, minimum up and down times, and ramp rates and costs. Since the modeling of dispatchable injections and offtakes is quite similar, only the constraints for the former are described here. They only differ in the provision of reserve capacity: while a potential increase in injection output contributes to the provision of upward reserve, a potential increase in offtake output contributes to the provision of downward reserve, and vice versa for a potential decrease in output. While the operation of dispatchable generators is fully described by (3.5)-(3.31), storage operation is additionally subject to the offtake constraints and the constraints discussed in Section 3.2.6.

Commitment constraints

A cluster's number of online units can change by starting up offline units or shutting down online units (3.5). It is limited to the maximum available number of online units, determined by the ratio of the installed capacity and typical unit size (3.6). The number of offline units that can start up, or be reserved to start up to provide reserve, is limited to the units that have been offline for at least the minimum down time (3.7). Similarly, the number of online units that can shut down, or be reserved to shut down to provide reserve, is limited to the units that have been online for at least the minimum up time (3.8):

$$n^{\text{inj}}_{i,h+1} = n^{\text{inj}}_{i,h} + n^{\text{su,inj}}_{i,h} - n^{\text{sd,inj}}_{i,h}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.5}$$

$$n^{\text{inj}}_{i,h} \leq p^{\text{inst,inj}}_{i} / P^{\text{inj}}_{i}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.6}$$

$$n^{\text{su,inj}}_{i,h} + \sum_{r \in \mathbb{RU}} n^{\text{sur,inj}}_{r,i,h} \leq p^{\text{inst,inj}}_{i} / P^{\text{inj}}_{i} - n^{\text{inj}}_{i,h} - \sum_{z \in \mathbb{Z}} n^{\text{sd,inj}}_{i,h-z}, \quad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.7}$$

$$n^{\text{sd,inj}}_{i,h} + \sum_{r \in \mathbb{RD}} n^{\text{sdr,inj}}_{r,i,h} \leq n^{\text{inj}}_{i,h} - \sum_{w \in \mathbb{W}} n^{\text{su,inj}}_{i,h-w}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}. \tag{3.8}$$

Output level constraints

A cluster's output level can change by ramping online units up or down, starting up offline units, or shutting down online units (3.9). The output level is limited by the generation limits of the online units (3.10)-(3.11). Units starting up have to at least reach the minimum output level, and are constrained by the start-up ramp rate (3.12)-(3.13). A technology's start-up ramp rate is defined as the maximum of the required ramp rate to reach the minimum output level over one time step and the spinning ramp rate to allow all technologies to start-up in a single hourly time step. Similarly, units shutting down have to be able to ramp down to a zero output level from at least the minimum output level, and are constrained by the shut-down ramp rate (3.14)-(3.15), which is defined similar to the start-up ramp rate. Ramping online units up and down is limited by the spinning ramp rate, while ensuring that ramping ability reserved for reserve provision is accounted for separately from the ramping that occurs in the scheduling phase to provide energy services (3.16)-(3.17). In addition to the spinning ramp rate, the ramping ability for online units is also constrained by the capacity available to perform spinning ramping (3.18)-(3.19):

$$p_{i,h+1}^{\mathrm{inj}} = p_{i,h}^{\mathrm{inj}} + p_{i,h}^{\mathrm{ru,inj}} - p_{i,h}^{\mathrm{rd,inj}} + p_{i,h}^{\mathrm{su,inj}} - p_{i,h}^{\mathrm{sd,inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.9)$$

$$p_{i,h}^{\mathrm{inj}} \geq n_{i,h}^{\mathrm{inj}} \cdot P_i^{\mathrm{min,inj}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.10)$$

$$p_{i,h}^{\mathrm{inj}} \leq n_{i,h}^{\mathrm{inj}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.11)$$

$$p_{i,h}^{\mathrm{su,inj}} \geq n_{i,h}^{\mathrm{su,inj}} \cdot P_i^{\mathrm{min,inj}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.12)$$

$$p_{i,h}^{\mathrm{su,inj}} \leq n_{i,h}^{\mathrm{su,inj}} \cdot R_i^{\mathrm{su,inj}} \cdot T^{\mathrm{h}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.13)$$

$$p_{i,h}^{\mathrm{sd,inj}} \geq n_{i,h}^{\mathrm{sd,inj}} \cdot P_i^{\mathrm{min,inj}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.14)$$

$$p_{i,h}^{\mathrm{sd,inj}} \leq n_{i,h}^{\mathrm{sd,inj}} \cdot R_i^{\mathrm{sd,inj}} \cdot T^{\mathrm{h}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.15)$$

$$p_{i,h}^{\mathrm{ru,inj}} + \sum_{\mathbb{RU}} r_{r,i,h}^{\mathrm{s,inj}} \leq (n_{i,h}^{\mathrm{inj}} - n_{i,h}^{\mathrm{sd,inj}}) \cdot R_i^{\mathrm{s,inj}} \cdot T^{\mathrm{h}} \cdot P_i^{\mathrm{inj}}, \quad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.16)$$

$$p_{i,h}^{\mathrm{rd,inj}} + \sum_{\mathbb{RD}} r_{r,i,h}^{\mathrm{s,inj}} \leq (n_{i,h}^{\mathrm{inj}} - n_{i,h}^{\mathrm{sd,inj}} - \sum_{\mathbb{RD}} n_{r,i,h}^{\mathrm{sdr,inj}})$$

$$\cdot R_i^{\mathrm{s,inj}} \cdot T^{\mathrm{h}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.17)$$

$$p_{i,h}^{\mathrm{ru,inj}} + \sum_{\mathbb{RU}} r_{r,i,h}^{\mathrm{s,inj}} \leq (n_{i,h}^{\mathrm{inj}} - n_{i,h}^{\mathrm{sd,inj}}) \cdot P_i^{\mathrm{inj}}$$

$$-(p_{i,h}^{\mathrm{inj}} - p_{i,h}^{\mathrm{sd,inj}}), \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}, \quad (3.18)$$

$$p_{i,h}^{\mathrm{rd,inj}} + \sum_{\mathbb{RD}} r_{r,i,h}^{\mathrm{s,inj}} \leq (p_{i,h}^{\mathrm{inj}} - p_{i,h}^{\mathrm{sd,inj}} - \sum_{\mathbb{RD}} r_{r,i,h}^{\mathrm{sd,inj}})$$

$$-(n_{i,h}^{\mathrm{inj}} - n_{i,h}^{\mathrm{sd,inj}} - \sum_{\mathbb{RD}} n_{r,i,h}^{\mathrm{sdr,inj}}) \cdot P_i^{\mathrm{min,inj}} \cdot P_i^{\mathrm{inj}}, \qquad \forall\, i \in \mathbb{ID}, h \in \mathbb{H}. \quad (3.19)$$

Reserve provision constraints

Dispatchable injection technologies provide upward reserve through online units that can increase their output and offline units that can start up (3.20), and downward reserve through online units that can decrease their output or shut down (3.21). Contracting FCR with injection technology i is limited by the technology's FCR-specific spinning ramp rate (3.22), (3.25), while contracting

FCR plus aFRR is limited by the aFRR-specific spinning ramp rate (3.23), (3.26), and contracting FCR plus aFRR plus mFRR is limited by the mFRR-specific spinning ramp rate (3.24), (3.27). Units providing reserve through starting up or shutting down are also limited by this reserve-specific ramping ability, and need to be able to overcome at least the minimum output level (3.28)-(3.31):

$$r^{\text{inj}}_{r,i,h} = r^{\text{s,inj}}_{r,i,h} + r^{\text{su,inj}}_{r,i,h}, \qquad \forall r \in \mathbb{RU}, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.20}$$

$$r^{\text{inj}}_{r,i,h} = r^{\text{s,inj}}_{r,i,h} + r^{\text{sd,inj}}_{r,i,h}, \qquad \forall r \in \mathbb{RD}, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.21}$$

$$\sum_{r \in \mathbb{RUF}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h}) \cdot R^{\text{s,r,inj}}_{fcr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.22}$$

$$\sum_{r \in \mathbb{RUA}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h}) \cdot R^{\text{s,r,inj}}_{afrr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.23}$$

$$\sum_{r \in \mathbb{RU}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h}) \cdot R^{\text{s,r,inj}}_{mfrr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.24}$$

$$\sum_{r \in \mathbb{RDF}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h} - \sum_{r \in \mathbb{RD}} n^{\text{sdr,inj}}_{r,i,h})$$

$$\cdot R^{\text{s,r,inj}}_{fcr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.25}$$

$$\sum_{r \in \mathbb{RDA}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h} - \sum_{r \in \mathbb{RD}} n^{\text{sdr,inj}}_{r,i,h})$$

$$\cdot R^{\text{s,r,inj}}_{afrr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.26}$$

$$\sum_{r \in \mathbb{RD}} r^{\text{s,inj}}_{r,i,h} \leq (n^{\text{inj}}_{i,h} - n^{\text{sd,inj}}_{i,h} - \sum_{r \in \mathbb{RD}} n^{\text{sdr,inj}}_{r,i,h})$$

$$\cdot R^{\text{s,r,inj}}_{mfrr,i} \cdot P^{\text{inj}}_{i}, \qquad \forall i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.27}$$

$$r^{\text{su,inj}}_{r,i,h} \geq n^{\text{sur,inj}}_{r,i,h} \cdot P^{\text{min,inj}}_{i} \cdot P^{\text{inj}}_{i}, \qquad \forall r \in \mathbb{RU}, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.28}$$

$$r^{\text{su,inj}}_{r,i,h} \leq n^{\text{sur,inj}}_{r,i,h} \cdot R^{\text{s,r,inj}}_{r,i} \cdot P^{\text{inj}}_{i}, \qquad \forall r \in \mathbb{RU}, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.29}$$

$$r^{\text{sd,inj}}_{r,i,h} \geq n^{\text{sdr,inj}}_{r,i,h} \cdot P^{\text{min,inj}}_{i} \cdot P^{\text{inj}}_{i}, \qquad \forall r \in \mathbb{RD}, i \in \mathbb{ID}, h \in \mathbb{H}, \tag{3.30}$$

$$r^{\text{sd,inj}}_{r,i,h} \leq n^{\text{sdr,inj}}_{r,i,h} \cdot R^{\text{s,r,inj}}_{r,i} \cdot P^{\text{inj}}_{i}, \qquad \forall r \in \mathbb{RD}, i \in \mathbb{ID}, h \in \mathbb{H}. \tag{3.31}$$

3.2.5 Intermittent injection constraints

Renewable generation volumes are driven by weather conditions and support schemes, rather than by electricity prices. As such, they are usually modeled as negative load, resulting in a residual load to be met by dispatchable units. However, the renewable generators' participation in electricity markets is becoming increasingly active, with the possibility to curtail output. They have close-to-zero (or even negative if subsidized) marginal costs, a time-varying maximum power output, and limited operating constraints. The time-varying RES output is calculated by using a normalized feed-in profile, which is scaled by the installed capacity. This available output can either be injected in the grid to be consumed, or curtailed in case of oversupply (3.32):

$$p_{i,h}^{\mathrm{inj}} + p_{i,h}^{\mathrm{l,inj}} = A_{i,h}^{\mathrm{res}} \cdot p_i^{\mathrm{inst,inj}}, \quad \forall\, i \in \mathbb{II}, h \in \mathbb{H}. \tag{3.32}$$

Although RES may provide contracted reserve to the TSO if tender periods are sufficiently short (e.g., hours), they are not able to contribute in the provision of reserve in the analyzed case study due to the assumed monthly contract periods (Section 3.2.7). In current markets especially wind generators already provide downward reserve through noncontracted reserve for short periods of time. In the future, these may provide upward reserve as well when constantly performing under their availability limit, and PV systems may also provide reserve through improved control and aggregation.

3.2.6 Electricity storage constraints

Storage systems are subject to energy buffer dynamics and a limited cycle-life. Furthermore, a symmetrical development of charge and discharge power ratings is assumed.

During charging, only part of the consumed electric energy is converted to energy stored in the buffer due to a charge efficiency, while during discharging, only part of the stored energy is converted back into electric energy due to a discharge efficiency (3.33). These additions and removals have to respect the minimum and maximum storage capacity, while the available range to provide energy services is constrained in both directions by the margins that are contracted for reserve provision (3.34)-(3.35). Linear ramping is assumed from the current output level to the output after activation in $T_r^{1,\mathrm{r}}$. The energy capacity that is reserved for reserve provision is assumed to be the energy required for both the linear ramping and to maintain reserve provision up to $T_r^{2,\mathrm{r}}$ (Fig. 3.1).

Storage plants have a limited lifetime, which is either determined by the calendar life in case of infrequent use or by the cycle-life in case of frequent use. The calendar life is the maximum time that it can be used, independent from the operation, while the cycle-life takes into account the deterioration of the energy storage subsystem due to use [9, 92]. While the cycle-life limits the operation of BES, for PHS the cycle-life is sufficiently large such that the depreciation cost following cycling patterns is negligible. Although there is no direct constraint on the number of cycles during the considered optimization period, due to the limited cycle-life a constant targeted cycling rate is implied throughout the lifetime. If the cycling rate is lower than or equal to this targeted cycling rate, the additional depreciation cost from cycling is zero, otherwise it is positive (3.36):

$$e_{s,h+1} = e_{s,h} + (\eta_s^{\text{off}} \cdot p_{s,h}^{\text{off}} - p_{s,h}^{\text{inj}}/\eta_s^{\text{inj}}) \cdot T^{\text{h}}, \qquad \forall\, s \in \mathbb{S}, h \in \mathbb{H}, \quad (3.33)$$

$$e_{s,h} \geq (1/\eta_s^{\text{inj}}) \cdot \sum_{r \in \mathbb{RU}} \big[(r_{r,s,h}^{\text{inj}} \cdot T_r^{1,\text{r}})/2 + r_{r,s,h}^{\text{inj}} \cdot (T_r^{2,\text{r}} - T_r^{1,\text{r}})\big], \qquad \forall\, s \in \mathbb{S}, h \in \mathbb{H}, \quad (3.34)$$

$$e_{s,h} \leq e_s^{\text{inst}} - \eta_s^{\text{off}} \cdot \sum_{r \in \mathbb{RD}} \big[(r_{r,s,h}^{\text{off}} \cdot T_r^{1,\text{r}})/2 + r_{r,s,h}^{\text{off}} \cdot (T_r^{2,\text{r}} - T_r^{1,\text{r}})\big], \qquad \forall\, s \in \mathbb{S}, h \in \mathbb{H}, \quad (3.35)$$

$$c_s^{\text{cyc}} \geq C_s^{\text{inv,e}} \cdot (\eta_s^{\text{off}} \cdot \sum_{h \in \mathbb{H}} p_{s,h}^{\text{off}}/N_s^{\text{cyc}} - e_s^{\text{inst}}/N_s^{\text{cal,inj}}), \quad \forall\, s \in \mathbb{S}. \qquad (3.36)$$

3.2.7 Reserve sizing

FCR sizing

The required FCR is determined on the ENTSO-E level, and is set at 3 GW for the synchronous area of continental Europe, covering the outage of two of the largest elements (i.e., an N-2 criterion). This effort is shared over the different control zones according to their share in the system [93, 94]. In line with the volume currently contracted by Elia, an exogenously-determined FCR requirement of 100 MW in both the up and downward direction is included in the analyzed case study. Since Elia does not expect significant changes in the need for FCR [95], the endogenously-determined FCR requirement is zero.

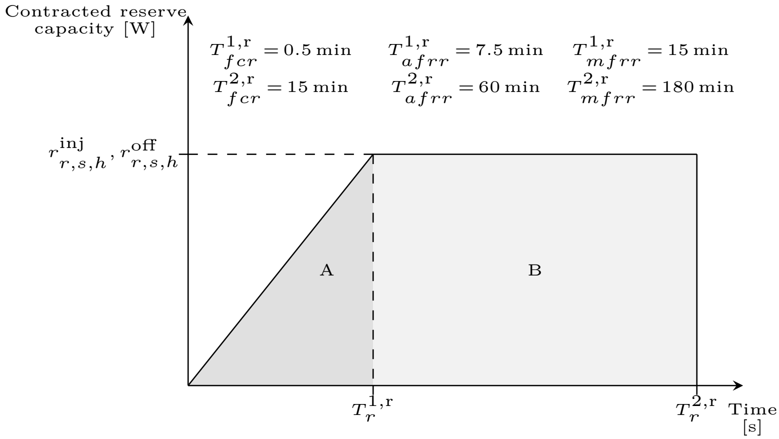
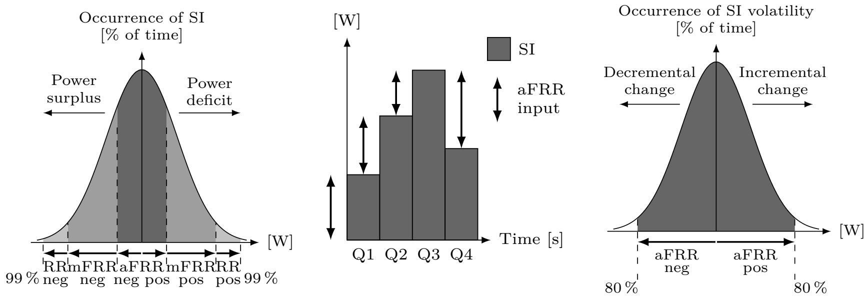


Figure 3.1: Energy storage capacity that needs to be reserved to provide reserve capacity (A + B).

FRR and RR sizing

The sizing of FRR and RR is the responsibility of the TSO, subject to ENTSO-E guidelines, and is based on both a deterministic and probabilistic assessment. The deterministic assessment considers the largest possible SI due to the loss of a single grid element. For Belgium the loss of a 1 GW interconnector is considered (i.e., the future Nemo interconnector). The FRR to be contracted has to at least be sufficient to cover such an event in both directions. The probabilistic assessment is based on recent historical SI time series of at least a full year, and determines the combined amount of FRR and RR to be contracted. ENTSO-E requests that the contracted amount of FRR and RR at least should be able to cover 99 % of the observed SIs in both directions (Fig. 3.2a), which is also imposed in the considered case study. In case the reserve sizing based on the probabilistic assessment results in lower reserve needs than the deterministic assessment, the latter is kept as a minimum for the amount of FRR that needs to be contracted. Although RR may be contracted to cover the gap between both in case the probabilistic assessment results in higher reserve needs than the deterministic analysis, this gap may also be covered by FRR as contracting RR capacity is not required. Since Elia does not contract RR, it is not considered here [93, 94]. Similar to the approach used by Elia [93], after having determined the total FRR need, a time series of the difference between the SI of consecutive quarter-hourly periods, representing the volatility of the SI, is considered to determine the share of aFRR (Fig. 3.2b). The aFRR to be contracted is determined by the required capacity to cover a certain percentage of the volatility of the SI in both directions. In the analyzed case study this percentage is assumed to be 80 %, in line with information provided by Elia [95]. The remaining FRR to be contracted to cover the total FRR need determines the amount of mFRR (Fig. 3.2c).



(a) Probabilistic sizing. (b) SI volatility. (c) Sizing of aFRR.

Figure 3.2: Probabilistic reserve sizing in line with the approach used by Elia.

Since the previously discussed sizing determines the FRR need for the current situation, it represents the exogenously-determined aFRR and mFRR requirements. In contrast to FCR, the endogenously-determined aFRR and mFRR requirements are nonzero due to increasing absolute levels of forecast errors with larger RES penetrations. For each intermittent RES technology a probability density function (PDF) of the normalized forecast errors is introduced by comparing the DA forecast with the RT output and describing the error by means of a normal distribution. Similar to the method for the exogenous component, the 99 % quantile in both directions determines the total endogenous FRR requirement. Afterwards, this total FRR requirement is again translated to endogenously-determined aFRR and mFRR needs. Again, the aFRR to be contracted is determined by the required capacity to cover 80 % of the forecast error's volatility. This is then complemented by mFRR to meet the total endogenously-determined FRR needs. It is assumed that variable RES only increase the need for upward reserve. In case of unexpected excess generation, the market design is expected to incentivize RES to curtail output if insufficient alternative downward flexibility is available.

Sizing and contract periods

In the analyzed case study the reserve requirements are sized on a yearly basis, while, in line with current reserve procurement trends in Europe, shorter contract periods (here monthly) for reserve capacity are considered. Abstraction is made from which share of the reserve requirements is to be procured by the TSO as a frequency control service to balance its control zone, or by market participants to keep their portfolio balanced.

3.3 Data, scenarios, and assumptions

3.3.1 Data

Four dispatchable generation technologies are taken into account, i.e., base, mid, peak, and high peak load, each having different techno-economic characteristics, and ordered in terms of decreasing fixed cost and increasing variable cost. The first two technologies are nuclear and coal power plants, respectively, whereas peak and high peak load technologies correspond to combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs), respectively. In addition, three variable RES technologies, i.e., onshore wind, offshore wind, and PV, and two electricity storage technologies, i.e., PHS and Li-ion BES, are considered. Although many different estimates for the cost data and technical parameters are available, the assumed input data is inspired by [61, 96, 97, 98], and is shown in Table 3.1 and Table 3.2. These values may deviate from actual levels, but the relative levels for the different technologies are believed to be representative.

To limit the reserve capacity that can be provided, the ramp rate on a minute basis $R_i^{\mathrm{m,inj}}/R_o^{\mathrm{m,off}}$ is used. In line with guidelines from the Belgian TSO Elia [99], we assume that capacity providing reserve has to be able to perform the promised change in power output in $T_r^{1,\mathrm{r}}$, being 0.5 min for FCR, 7.5 min for aFRR, and 15 min for mFRR (Fig. 3.1). As such, the technologies' spinning ramp rate for each reserve category $R_{r,i}^{\mathrm{s,r,inj}}/R_{r,o}^{\mathrm{s,r,off}}$ can be derived (e.g., $R_{r,i}^{\mathrm{s,r,inj}} = R_i^{\mathrm{m,inj}} \cdot T_r^{1,\mathrm{r}}$). Since the ramp rate on a minute basis is usually defined as being faster compared to the hourly ramp rate for continuous operation to provide energy services in the scheduling phase, the reserve-specific spinning ramp rate is then limited by this continuous operation ramp rate to avoid situations in which more ramping is possible in 7.5 min or 15 min than in an hour. While those fast ramp rates on a minute basis may be appropriate for infrequent use (i.e., reserve provision), they are believed to be too high for continuous operation (i.e., electricity generation), potentially incurring additional O&M costs.

We use hourly RES power output data from Elia [100] and consumption data from ENTSO-E [101], for Belgium for 2014. For this period PV is characterized by 1 054 full load hours, while onshore and offshore wind are characterized by 2 046 and 3 600 full load hours, respectively. Average consumption is 9 539 MW, fluctuating between a minimum of 6 623 MW and a maximum of 13 110 MW.

Table 3.1: Economic input parameters, fixed costs are annualized via annuities using a 5 % interest rate. Electricity storage charge and discharge (i.e., offtake and injection) parameters are assumed to be identical.

Name	$N_i^{\text{cal,inj}}$ [a]	Fixed costs: Total $C_i^{\text{inv,inj}}$ [€/kW]	Fixed costs: Total $C_s^{\text{inv,e}}$ [€/kWh]	Fixed costs: Annualized $C_i^{\text{inv,inj}}$ [€/kW]	Fixed costs: Annualized $C_s^{\text{inv,e}}$ [€/kWh]	Fixed costs: Annualized $C_i^{\text{fom,inj}}$ [€/kW]	Variable costs $C_i^{\text{fuel,inj}}$ [€/MWh]	Variable costs $C_i^{\text{vom,inj}}$ [€/MWh]	Variable costs $C_i^{\text{ra,inj}}$ [€/MW]	Variable costs $C_i^{\text{su,inj}}$ [€/MW]	Variable costs $C_i^{\text{sd,inj}}$ [€/MW]
Base	50	5 000	-	274	-	43	10	5	1.30	200	0
Mid	35	1 700	-	104	-	34	26	10	1.30	50	0
Peak	25	855	-	61	-	21	43	10	0.70	37	0
hPeak	15	486	-	47	-	12	66	10	0.30	25	0
PV	25	895	-	64	-	13	-	0	-	-	-
onWind	30	1 270	-	83	-	27	-	0	-	-	-
ofWind	30	2 600	-	169	-	80	-	0	-	-	-
BES	15	100	300	10	29	0	-	0	0	0	0
PHS	50	375	50	21	3	0	-	0	0	0	0

Table 3.2: Technical input parameters. Electricity storage charge and discharge (i.e., offtake and injection) parameters are assumed to be identical, except for the minimum load requirement ($P_i^{\text{min,inj}}/P_o^{\text{min,off}}$). In addition, $T_i^{\text{mut,inj}}$ corresponds to $|\mathbb{W}|$, while $T_i^{\text{mdt,inj}}$ corresponds to $|\mathbb{Z}|$.

Name	P_i^{inj} [MW]	$P_i^{\text{min,inj}}$ [%]	$R_i^{\text{s,inj}}$ [%/h]	$R_i^{\text{m,inj}}$ [%/min]	η_s^{inj} [%]	$T_i^{\text{mut,inj}}$ [h]	$T_i^{\text{mdt,inj}}$ [h]	N_s^{cyc} [-]
Base	400	50	33	3	-	24	24	-
Mid	300	50	50	4	-	6	4	-
Peak	200	50	80	6	-	4	1	-
hPeak	100	10	100	10	-	1	1	-
BES	10	0	100	100	95	0	0	3000
PHS	100	30/70	100	50	87	0	0	∞

Using data from Elia, the exogenous aFRR and mFRR requirements are 157 MW and 843 MW, respectively, in both directions, while the endogenous aFRR and mFRR requirements amount to 0.01 MW and 0.12 MW per MW PV, 0.02 MW and 0.15 MW per MW onshore wind, and 0.05 MW and 0.33 MW per MW offshore wind, respectively, all in the upward direction.

Since a high RES curtailment cost corresponds to today's electricity markets with subsidies, and a zero (or low) RES curtailment cost corresponds to future markets without subsidies but with active RES participation, we assume a RES curtailment cost of 0 €/MWh. Finally, the cost of involuntary load shedding is set at 3 000 €/MWh, based on the price cap in the DA market of the CWE region.

3.3.2 Scenarios

The portfolio and operation of the system is optimized with an hourly time resolution. Five increasing targets for the share of RES in the final consumption, ranging from 0 % to 50 %, are considered. Furthermore, four storage scenarios are considered. The reference storage scenario, in which no storage is available to be installed, serves as benchmark. By comparing it with the results of the other three scenarios, the role and value of electricity storage can be analyzed. In scenario 1 both PHS and BES are available to be installed, while in scenario 2 the available PHS energy capacity is limited to 8.7 GWh. The chosen upper limit is based on the conventional Belgian PHS capacity, considering the currently developed capacity, i.e., Coo-Trois-Ponts I and II, and Plate-Taille, and the recently proposed extension of the Coo-Trois-Ponts PHS plant [3]. Finally, scenario 3 studies the impact of a future reduction of the energy-related investment cost of BES from 300 €/kWh to 150 €/kWh, while keeping the upper limit for PHS at 8.7 GWh.

3.3.3 Assumptions

First, although the test system includes system load and RES generation characteristics for Belgium, we abstract from an actual system with capacity legacy but instead adopt a long-term greenfield approach. While this does not allow to derive deployment scenarios or optimal pathways, it gives broadly applicable system-independent insights in the role and value of storage technologies, and in the interdependency of the included flexibility options. The developed GEP model however allows to include capacity legacy by imposing starting values per technology, and can thus also be used for studies that focus on optimal future portfolios for specific countries or regions.

Second, since not all services that storage can provide are considered (e.g., voltage support, congestion management, and black-start capabilities), this analysis may underestimate the total value of storage for the system.

Third, since the different flexibility sources are to some extent interchangeable, the transition to a RES-based power system can be achieved through various portfolios of flexibility sources. As flexible demand is not considered, the results may overestimate the absolute supply of flexibility by storage. In addition, since exchange with neighboring regions is not considered, the possibility to import flexibility supply or to smoothen system variability is neglected, thereby most likely overestimating the need for local flexibility. Furthermore, the linear scaling of historic RES generation profiles further overestimates absolute flexibility needs, as it neglects possibly smoother RES generation profiles by future changes in geographical distribution.

Fourth, in GEP it is common practice to ignore the internal grid, to not constrain the applicability of the results by the current network. We assume a copper plate as the grid can be upgraded in the long-run and we aim to derive broadly applicable insights, and in order to be able to solve numerically for a full year with high operational detail. Instead, GEP is typically considered separately from network expansion planning, with the GEP output serving as input for the network expansion planning model. We thus do not distinguish between the locations or voltage levels to which generation and storage capacities are connected. In real systems the total flexibility need may consist of needs at the transmission and distribution level, possibly requiring different technical solutions.

Fifth, the various sources of uncertainty (e.g., load, RES generation) are addressed with a deterministic approach, given the computational complexity due to the included high temporal and operational detail. This is in line with other GEP works including such detailed short-term operation, as for these models it is computationally impractical to consider the recent developments in stochastic UC formulations. Decisions are based on expected values of probabilistic input parameters, but three reserve products are contracted and scheduled to deal with deviations from these expected values, and thus to deal with uncertainty. The reserve sizing includes a deterministic and probabilistic assessment, and considers unexpected outages and unexpected variations in the load and RES generation. It provides both exogenous and endogenous reserve requirements. The latter increase with the installed variable RES capacity to deal with the increasing uncertainty in the system due to its limited predictability.

These simplifications contribute to the computational solvability of the presented combined long-term investment and detailed short-term operation model for a full year, and to the traceability of results. The aim is to derive general conclusions on the role and value of electricity storage in renewable power systems, thereby not focusing on absolute numbers in the results of individual scenarios, but on orders of magnitude and differences between the four scenarios.

3.4 Results

3.4.1 Total system cost

The availability of electricity storage lowers total system cost (Fig. 3.3). This is true for all three storage scenarios, and its explanation is threefold. First, storage can compensate the system's expected variability by storing base load and RES generation in times of low residual load, and (partly) replacing peak and high peak load generation in times of high residual load. As such, the rather inflexible base and mid load generation technologies can be operated more efficiently, while the need for flexible peak and high peak load generators decreases. The negative correlation among RES penetration and storage fuel cost, the latter being related to the energy losses and the price at which energy is stored, represents a valuable advantage for storage that increases with the RES target. Second, storage can compensate the system's unexpected variability by providing reserve. As such, inefficient scheduling to keep conventional generators online (partly-loaded) to provide spinning reserve can be reduced.[3] This lowers the incompressible part of supply, thereby decreasing RES curtailment in times of low residual demand, and contributes to efficient merit-order scheduling. Third, less RES capacity needs to be installed to reach the imposed RES targets. Excess RES generation that otherwise had to be curtailed can now be stored,

[3]Upward FCR and aFRR is provided as spinning reserve by base, mid, and peak generators as they cannot start-up in time to provide them as nonspinning reserve. In addition, all downward reserve categories are provided as spinning reserve by all conventional generators.

or simply generated to be consumed since the incompressible part of supply is lower with storage as flexibility provider compared to conventional generators.

Scenario 1 leads to the lowest system cost, while scenario 2 is still characterized by significant cost savings compared to the reference scenario but ends up at a higher total cost than scenario 1. Finally, in scenario 3, the total system cost decreases again compared to scenario 2 but remains well above scenario 1.

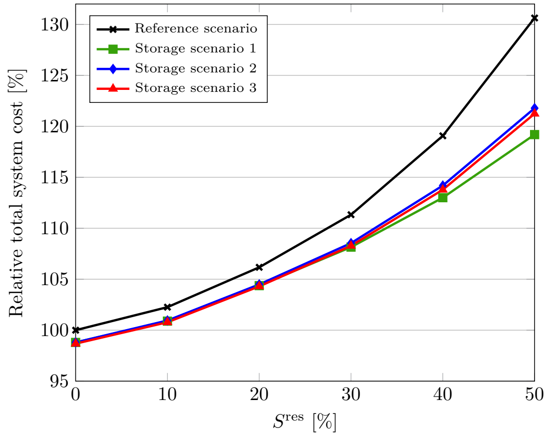
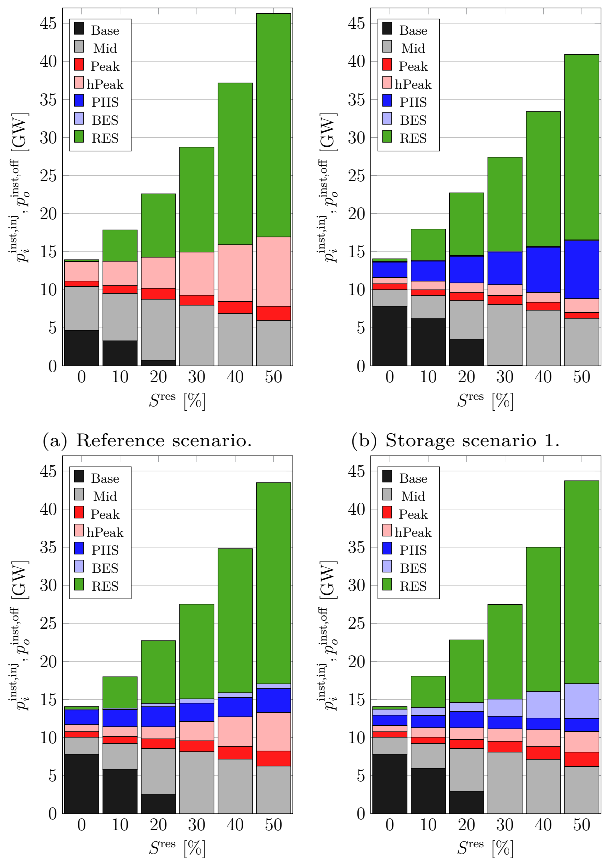


Figure 3.3: Total system cost relative to the case with a 0 % RES target in the reference scenario.

3.4.2 Generation and storage mix

Fig. 3.4 shows the installed capacities for the reference scenario and the three storage scenarios, based on which four observations can be made. First, when storage resources are available, less RES capacity is needed to reach the imposed RES target. Depending on the storage scenario, this leads to 9.7 %-10.4 %, 10.8 %-16.7 %, and 9.5 %-17.0 % less installed RES capacity to reach a 30 %, 40 %, and 50 % RES target, respectively. This may be important in countries where the available land area for wind turbines or PV systems is scarce or faces opposition. Second, storage resources allow base load plants to remain in the optimal mix to a larger extent. Depending on the storage scenario, its installed capacity increases by 67.2 %-67.9 %, 76.2 %-88.7 %, and 244.0 %-369.3 % for a 0 %, 10 %, and 20 % RES target, respectively. In addition, in scenario 1 base load is even included (to a very limited extent) up to a 30 % RES target compared to only a 20 % RES target for the other scenarios. Third, storage reduces the need for peak and high peak generators. Depending on the storage scenario, the installation of such power plants decreases by 43.1 %-62.6 %, 38.7 %-74.4 %, and 36.0 %-76.6 % for a 30 %, 40 %, and 50 % RES target, respectively. The impact of observations one to three is always the largest in storage scenario 1 and the smallest in scenario 2, with the impact in scenario 3 in between. Fourth, when the maximum available PHS energy capacity is limited due to geographical constraints, PHS is mainly replaced by peak and high peak generation capacity, and only to a limited extent by BES at the current energy-related BES investment cost. At a future lower investment cost of the BES energy storage subsystem again less peak and high peak generation is needed while the installed BES power rating even surpasses PHS from a 30 % RES target onwards.



(a) Reference scenario.

(b) Storage scenario 1.

(c) Storage scenario 2.

(d) Storage scenario 3.

Figure 3.4: Optimal mix in different storage scenarios given a variety of RES targets.

Fig. 3.5 shows that a relationship between the imposed RES target and installed flexible resources (i.e., peak and high peak generation, PHS, and BES) can be observed independent from the analyzed scenario. This may represent the flexibility need at different RES targets, met by the different flexibility sources. Although no absolute numbers can be concluded upon since this is most likely dependent on the residual load profile, it shows that flexibility sources are to some extent interchangeable. This is important for regulators and policy-makers to take into account, e.g., when deciding on capacity markets, as these generally result in current gas-fired conventional generators being contracted to remain operational (e.g., strategic reserve in Belgium, capacity auction in the UK). As such, this may constrain the development of alternative and (potentially) more economically viable flexibility sources.

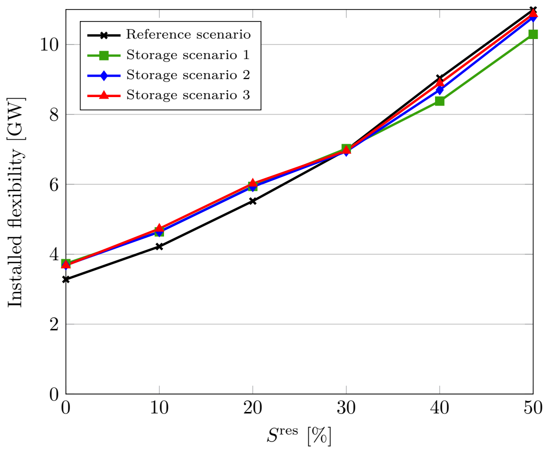


Figure 3.5: Relationship between the installed flexible capacity and imposed RES target.

Finally, an analysis of the energy, power, and E2P ratio characteristics of the installed storage resources in the three storage scenarios is provided in Table 3.3. First, in scenario 1 a significant amount of PHS is developed, both in terms of energy and power, which includes an E2P ratio between 4.56 h and 8.39 h. The developed PHS is used for both energy-related and power-related services. In contrast, BES energy capacity and power rating is only developed to a limited extent, with the former being small compared to the latter. The resulting E2P ratio is between 0.24 h and 0.47 h, as BES is almost exclusively used to provide power-related frequency control in this scenario. Second, in scenario 2 the total available PHS energy capacity is immediately developed from a 0 % RES target, while the accompanying installed PHS power rating increases moderately with the RES target. This leads to E2P ratios between 2.80 h and

4.49 h. Scenario 2 includes both higher BES energy capacity and power rating levels compared to scenario 1, but E2P ratios have similar orders of magnitude (i.e., 0.25 h-0.82 h). While BES takes over part of the power-related services of PHS, flexible generators cover its energy-related services. Third, scenario 3 shows that the available PHS energy capacity is fully developed from the start even at a lower energy-related BES investment cost, but less power rating is developed. This leads to higher E2P ratios for PHS compared to scenario 2, i.e., 4.09 h-6.43 h. Significantly more BES energy capacity is developed, surpassing the maximum available PHS energy capacity at a 50 % RES target, as well as more power rating, surpassing the installed PHS power rating at high RES targets. Although the BES E2P ratio increases to 1.10 h-2.26 h, it is still well below the PHS E2P ratio. This analysis shows that both short-to-mid and mid-to-long-term storage is needed: even when PHS would be available to an unlimited extent, BES is developed, and even when the energy-related BES investment cost would decrease towards the future, the available PHS energy capacity is still fully developed. Although these sources compete to provide some flexibility services, they complement each other to meet the system's total flexibility demand in the most efficient way.

3.4.3 Reserve provision

Fig. 3.6, Fig. 3.7, and Fig. 3.8 show the average FCR, aFRR, and mFRR provision, respectively, by the different generation and storage technologies for the different scenarios.

In the reference scenario, upward FCR is provided by online conventional generators that have head room available to provide this reserve. At low RES targets it is mainly provided by mid load plants, while at high RES targets a significant share is provided by high peak load plants. The different storage scenarios show that when storage is available, BES is about the sole provider, with PHS providing a minor share in scenario 2. In contrast to conventional generation technologies and PHS, BES does not have to be committed to provide upward FCR. In the reference scenario, and in the different storage scenarios at low RES targets, downward FCR is provided by online generation capacity, as they can provide this service fairly easy by ramping down. At high RES targets, and when storage is available to be installed, storage provides the largest share of downward FCR. As such, no conventional generators have to stay online (must-run) to solely provide this service, especially taking into account the assumed monthly contract periods. In scenario 1 and 2 both PHS and BES provide downward FCR, with the latter providing the major share, while at reduced energy-related BES investment costs it takes over PHS's share.

Table 3.3: Storage characteristics in the different storage scenarios at different RES targets.

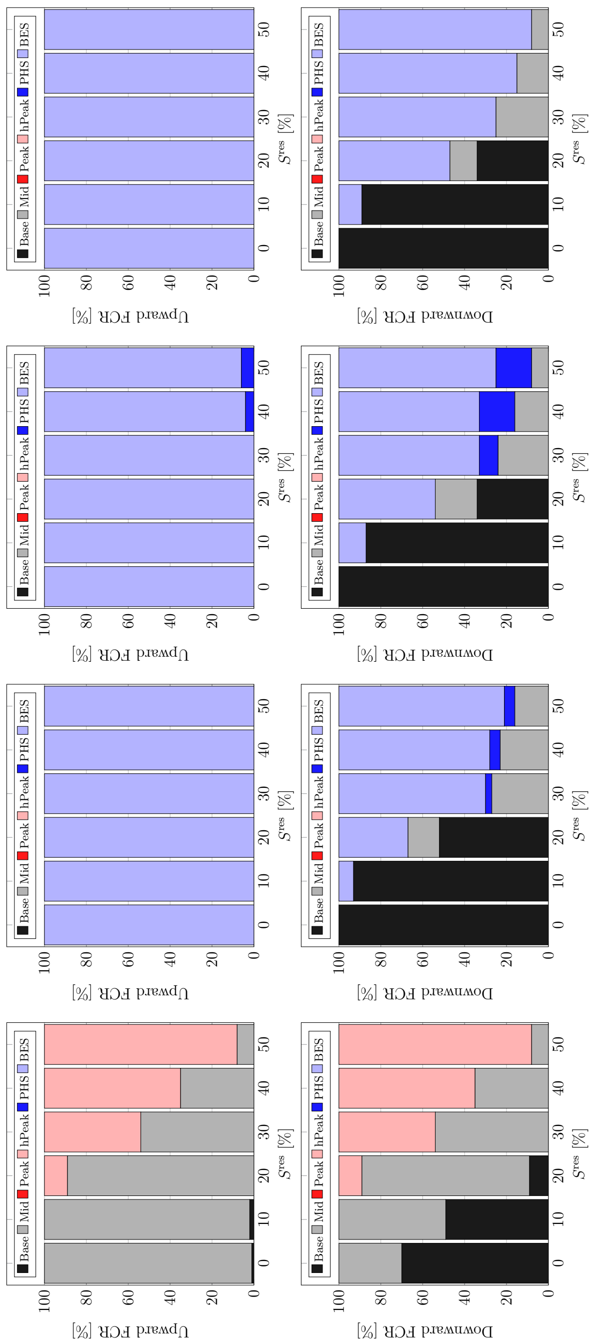
			PHS						BES					
			0 %	10 %	20 %	30 %	40 %	50 %	0 %	10 %	20 %	30 %	40 %	50 %
Scenario 1	e_s^{inst}	[GWh]	9.72	12.54	15.95	21.29	42.23	63.84	0.03	0.03	0.04	0.05	0.05	0.05
	$p_i^{\text{inst,inj}}, p_o^{\text{inst,off}}$	[GW]	2.01	2.63	3.50	4.30	5.96	7.61	0.10	0.10	0.11	0.11	0.11	0.11
	E2P ratio	[h]	4.83	4.78	4.56	4.95	7.08	8.39	0.24	0.27	0.36	0.47	0.46	0.46
Scenario 2	e_s^{inst}	[GWh]	8.70	8.70	8.70	8.70	8.70	8.70	0.03	0.12	0.35	0.44	0.51	0.49
	$p_i^{\text{inst,inj}}, p_o^{\text{inst,off}}$	[GW]	1.94	2.26	2.64	2.42	2.54	3.12	0.11	0.20	0.45	0.55	0.62	0.62
	E2P ratio	[h]	4.49	3.85	3.29	3.60	3.43	2.8	0.25	0.58	0.78	0.81	0.82	0.79
Scenario 3	e_s^{inst}	[GWh]	8.70	8.70	8.70	8.70	8.70	8.70	0.86	1.58	1.61	4.34	7.05	10.29
	$p_i^{\text{inst,inj}}, p_o^{\text{inst,off}}$	[GW]	1.35	1.62	2.13	1.66	1.55	1.71	0.78	1.06	1.19	2.26	3.47	4.56
	E2P ratio	[h]	6.43	5.37	4.09	5.23	5.62	5.09	1.10	1.49	1.35	1.92	2.03	2.26

In the reference scenario upward aFRR is provided by online high peak load plants, while storage is the major upward aFRR provider in the different storage scenarios. In scenario 1 PHS is the main provider, while in scenario 2 its share decreases at the expense of BES, and upward aFRR provision is shared. In scenario 3 BES is the main provider. Similar to FCR, at low RES targets the downward component is provided by ramping down base and mid load plants that are online most of the time anyway. When storage is available, and at higher RES targets, base and mid load power plants would no longer be constantly online following efficient scheduling. Here, PHS provides the largest share in scenario 1, while both PHS and BES provide a large share in scenario 2 and 3, with BES becoming downward aFRR's main provider at high RES targets.

If storage resources are not available to be installed, upward mFRR is provided by high peak load generators, as they do not have to be committed at part-load but can start up fast enough. In storage scenario 1, the share of PHS of this energy-intensive reserve increases with the RES target. When the PHS energy capacity is limited, peak and high peak load plants again provide the largest share with PHS providing the remaining upward mFRR, and at lower BES energy-related investment cost they may provide a share of upward mFRR as well at the expense of high peak load generators. Again, downward mFRR is mostly provided by online conventional generators. When storage resources are available they provide an increasing share of downward mFRR as the RES target increases, since the amount of conventional generators that have to remain online for a month can be decreased. At current costs PHS is about the sole storage technology providing downward mFRR, while in scenario 3 BES provides a significant share as well.

3.5 Conclusions

In the context of RES-driven power systems, short-term operating constraints and requirements are important to consider during long-term planning analyses. They are key drivers for flexibility, but large problem sizes and long computation times have limited the extent to which they are included in policy and planning models. We present the development of a combined, and simultaneously solved, long-term investment and short-term operation model with high temporal and operational detail. It decides on the installed generation and storage capacities to cover the demand for energy and reserve capacity at lowest cost, given short-term operating constraints and residual demand variations, for increasing RES generation targets. Short-term operation is modeled through a continuous



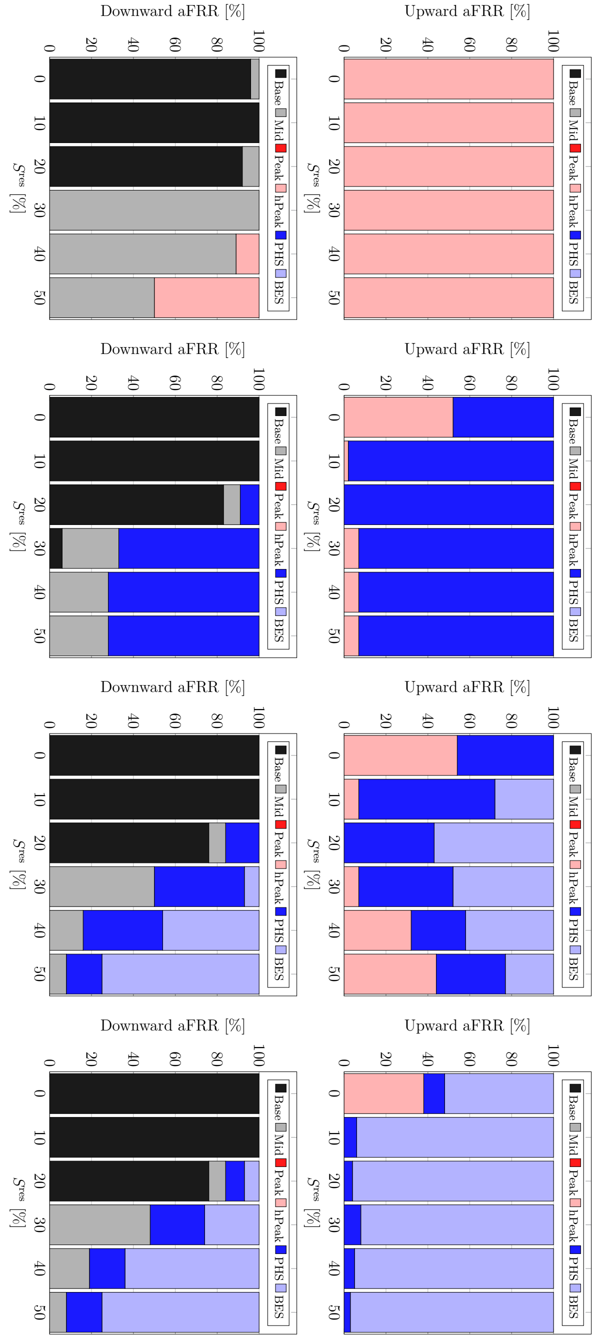
(a) Reference scenario.

(b) Storage scenario 1.

(c) Storage scenario 2.

(d) Storage scenario 3.

Figure 3.6: Average FCR provision in different storage scenarios given a range of RES targets.



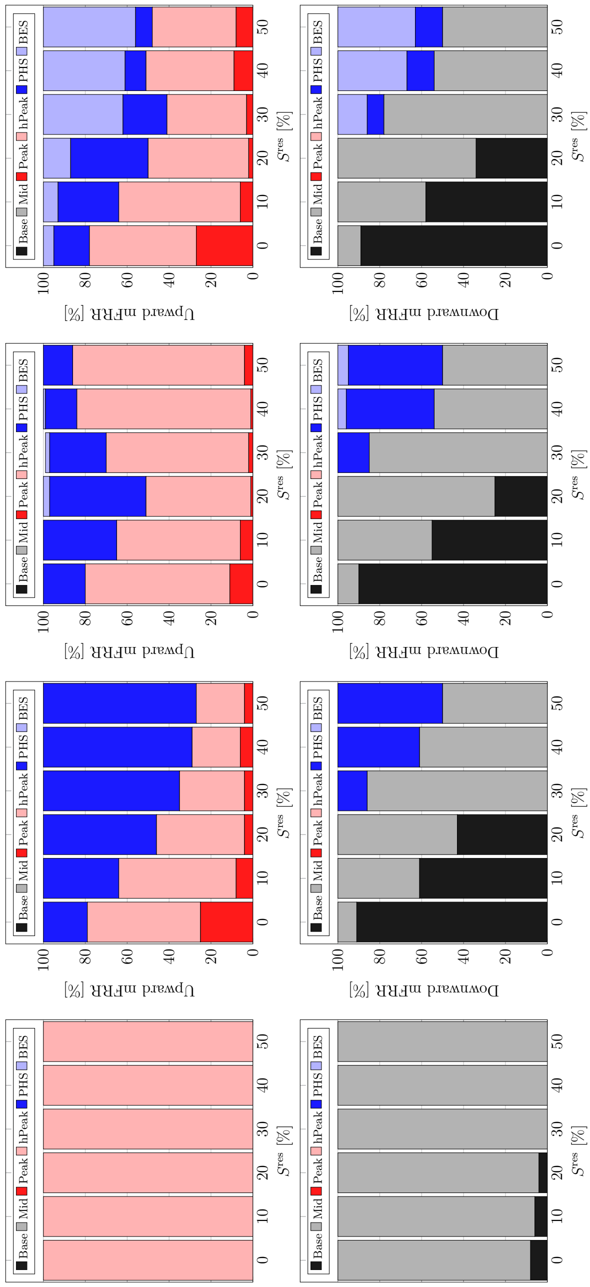
(a) Reference scenario.

(b) Storage scenario 1.

(c) Storage scenario 2.

(d) Storage scenario 3.

Figure 3.7: Average aFRR provision in different storage scenarios given a range of RES targets.



(a) Reference scenario.

(b) Storage scenario 1.

(c) Storage scenario 2.

(d) Storage scenario 3.

Figure 3.8: Average mFRR provision in different storage scenarios given a range of RES targets.

relaxation of the technology-clustered formulation of the UC problem. This allows for a better insight in the role and value of storage as flexibility source.

The availability of storage resources lowers the overall system cost. We show that this can be explained through its contribution to compensate the system's expected and unexpected variability, and because less RES capacity needs to be installed to reach the imposed RES targets. First, storage has the ability to compensate the former by storing base load and RES generation in times of low residual demand, and by partly replacing peak and high peak generation in times of high residual demand. Second, storage has the ability to compensate the latter by providing reserves, thereby reducing the need for inefficient scheduling to accommodate must-run (partly-loaded) conventional generators to provide spinning reserve. Third, less RES needs to be installed to reach RES targets, as excess RES generation that otherwise had to be curtailed can now be stored, or simply generated to be consumed since the incompressible part of supply is lower.

The detailed modeling of frequency control allows for two main conclusions. First, independent from the storage scenario BES provides a significant share of FCR, while it is only when PHS is geographically constrained that BES provides significant shares of aFRR as well. Finally, when in addition the cost for the energy storage subsystem decreases, BES appears to be well-suited to provide FCR and aFRR, as well as mFRR. This provides conditions for which BES is a favorable technology to provide the different reserve products. Second, we quantitatively show how the interaction between energy and reserve markets leads to storage contributing to the provision of upward reserve at all RES targets, and to the provision of downward reserve only at high RES targets.

Results show that there is a need for both short-to-mid-term BES and mid-to-long-term PHS. PHS plants mainly provide energy services to the system, i.e., shifting energy in time, and energy-intensive reserve products, while BES systems mainly provide power-related reserve products. Even when the available PHS energy capacity would not be restricted by geographical conditions, BES is developed, and even when the energy-related BES investment cost would decrease towards the future, the available PHS capacity is still fully developed. Although these sources compete to provide some flexibility services, they complement each other to meet the system's total demand for flexibility.

Furthermore, we conclude that a relation is present between the imposed RES target and installed flexible resources, independent from the analyzed scenario. This confirms that flexibility sources are to some extent interchangeable. It can be hypothesized that if due to capacity legacy or market design conventional flexible capacity remains operational in the system, this affects the development of alternative and (potentially) more economic flexibility sources.

Chapter 4

Short-term electricity markets

Interactions between the design of short-term electricity markets in the CWE region and power system flexibility

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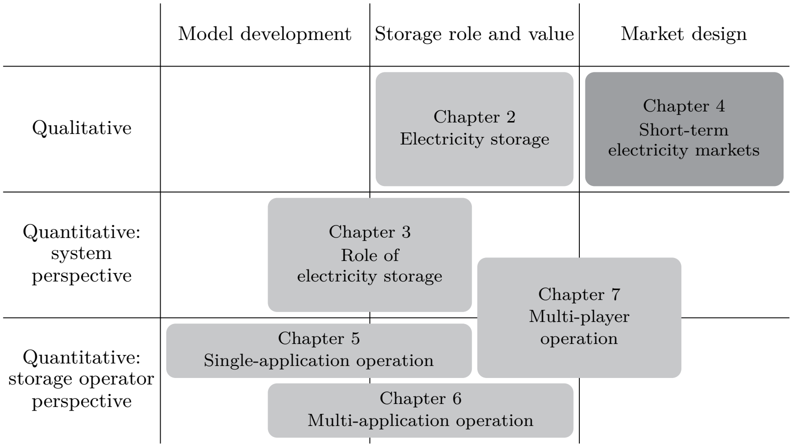
The first author is the main author of this article. The contributions of the first author include the literature study, the review of the current market design, the analyses of the implications for flexibility, and the writing of the manuscript. Support in the analyses and the writing of the text, and supervision, are provided by the second, third, and fourth author.

Abstract:

Short-term electricity markets are generally defined as markets that take place from the day-ahead stage until physical generation and consumption. These markets include day-ahead, intra-day, and real-time balancing markets. In Europe, the first two are managed by power exchanges, while the third consists of reserve procurement and imbalance settlement and is operated by the local transmission system operator. Short-term markets are important tools to deal with net demand variability in the system, in which the need for flexibility is expressed and its provision is valorized. Due to the ongoing integration of

variable renewables in the generation mix, the system's variability is increasing as a result of the limited controllability and predictability of those resources. As such, these markets become increasingly important. The contribution of this chapter is a comprehensive up-to-date discussion of the key design parameters and functioning of all three short-term markets, and their impact on the demand for and supply of flexibility. An understanding of the design and its implications is useful to policy-makers who are considering changes to facilitate the integration, availability, or valorization of flexibility, while also contributing to the decision-making of flexibility investors and operators. The geographical scope is the Central Western European region, including the Belgian, French, German, and Dutch market zones.

Positioning:



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4.1 Introduction

Electricity markets differ from other commodity markets because electric energy is a RT product. Therefore, it is necessary to maintain a balance between generation and consumption at all times. Historically, electricity was generated by large centralized thermal and hydro power plants to match demand, with the help of fuel storage and PHS plants to compensate for the variability of consumption and the partial inflexibility of conventional power plants. The ongoing transition towards variable RES, i.e., wind turbines and PV systems, challenges the reliable operation of the power system. Their limited controllability and predictability results in an increasing need for flexibility, i.e., the ability to provide upward and downward power adjustments to compensate for temporary imbalances between generation and consumption [9, 10]. At the same time, the flexibility offered by the generation side is threatened by closure of conventional power plants that are currently experiencing decreasing profitability due to lower electricity prices and a limited number of operating hours. The former is due to the close-to-zero marginal cost of RES, while the latter can be attributed to the merit-order effect of RES [11, 12]. Further, a paradigm shift is taking place from a situation where generation was dispatched to follow inflexible demand to a situation in which flexibility is provided by both generation and consumers. However, there will be a need for electricity storage as well to fill the remaining gap, and for the further development of interconnection capacity and integration of adjacent markets to access flexible resources in neighboring regions [13].

4.1.1 Scope and motivation

In Europe, market players self-schedule their generation, consumption, and storage assets as a result of trading, which starts years prior to delivery and continues almost until RT. This is accomplished by a series of sequential markets, of which the earliest are the so-called unstandardized forward and standardized future markets. These markets usually continue until one day before delivery, when the power exchange holds its centrally organized DA market. After clearing of the DA market, ID trading is possible until close-to-RT. After gate closure of the ID market, the TSO is responsible to keep the system balanced. To maintain this balance, the TSO contracts and activates reserve capacity from balance service providers (BSPs) at the procurement side, and settles imbalance positions with balance responsible parties (BRPs) at the settlement side of the balancing market [102, 103]. We focus on the CWE region, which, consistent with common definitions (e.g., [104, 105, 106]), includes the Belgian, French, German, and Dutch market zones.

Due to techno-economic constraints of power plants, and limited ability to foresee renewable generation, outages of power plants and grid elements, and load behavior, it is in short-term electricity markets where the need for flexibility is most apparent, and providers of flexibility are financially rewarded. These markets are generally defined as those taking place from the DA stage until physical generation and consumption in RT, i.e., including DA, ID, and RT markets.[1] Currently these markets are becoming more important due to increasing levels of variability in the system, resulting from the ongoing integration of variable RES. A good understanding of the current design and functioning of these markets, as well as of possible future developments, is a foundation for analyzing the need for and provision of flexibility.

4.1.2 Context: the theory of short-term energy pricing and rewarding of flexibility

Despite the attention that the literature pays to the need for more flexibility in power markets, we must first ask why that flexibility would not be forthcoming in pure energy markets, and why additional products (e.g., the flexible ramping products traded in some markets in the US) may be needed. Indeed, if the issues of within-interval ramps and abrupt changes in demand at the start and end of intervals are disregarded, then in theory, energy prices alone can support optimal flexible operation of generating resources without a need for separate payments for flexibility. Furthermore, energy prices can also support optimal investment in flexible vs. inflexible capacity. In brief, the proof of these perhaps surprising propositions proceeds as follows.

Assume that all resources make truthful offers to the market; there are no floors or caps to prices; consumers bid their true willingness-to-pay, so that in cases of shortage, prices rise to the marginal value of consumption; and there is no uncertainty.

These results follow from formulating the generation capacity expansion problem as a linear program, including continuous capacity, discrete chronologic intervals (e.g., hours), ramp rate limits, and, if desired, convex approximations of commitment constraints. This linear program yields a primal solution that is not only the social least-cost solution, but also represents a market equilibrium among price-taking generators who compete to supply a fixed demand in each hour [107]. The model also yields energy prices (the Lagrange multipliers associated with the hourly energy balances) that support the optimal solution.

[1] In the context of this chapter DA and ID markets refer to those organized by the power exchanges. Bilateral OTC trading, in which market players agree on a trade contract by directly interacting with each other, is not in the scope of this chapter.

"Support" refers to the property that each generator's capacity and operating decisions are profit maximizing for that generator, given the prices: a generator cannot earn more profit by deviating in a feasible way from the primal solution. The only revenue earned by generators is from energy sales, showing that in theory only energy prices are needed to support optimal schedules, even when there is highly variable net demand with steep ramps. For instance, negative and positive price spikes associated with steep net load ramps will theoretically send the correct signals for operation and ultimately investment in this simplified world. Flexible generators earn more revenue and can justify their higher capacity costs because they can turn down and up to avoid negative price spikes and grab positive price spikes, respectively.

This result generalizes to a world of uncertainty with risk-neutral (expected profit maximizing) generators. If the generation capacity expansion model is formulated as a linear stochastic program with random (e.g., Markovian) net demand and RES generation, then it can be shown that the resulting stochastic prices support the optimal operations and capacity decisions by generators.

Therefore, justifications for the creation of flexibility products or paying separately for flexibility in addition to energy commodity prices require a rationale based on market failures. Such failures could include (1) lumpy/nonconvex investment and commitment decisions that are not appropriately reflected in prices; (2) price caps and floors that suppress spikes; (3) dispatch intervals (e.g., one hour) that are too long and average out spikes so that flexibility is not rewarded; or (4) failures in the investment market, e.g., political or highly risk-averse decision-making. The extent to which these failures provide distorted incentives for supplying flexibility has not been quantified and is an open research topic. In this chapter, we review the design and performance of existing short-term markets in the CWE region, focusing on how they reward flexibility, and where they might be reformed to provide improved incentives for providing that flexibility.

4.1.3 Literature review and contributions

Literature review on the design of short-term markets

In this section, we begin our review of how short-term markets in the CWE region incentivize flexibility by providing a comprehensive overview of the literature on the design of short-term markets in Europe. We divide the literature into three groups in the following three paragraphs. The focus of each reference is briefly highlighted, with Table 4.1 classifying those that consider particular market zones and short-term markets according to these two dimensions.

The first group of works discusses the short-term market design for individual market zones. Ref. [103] analyzes the occurrence of negative balancing prices in Belgium, while discussing the functioning of its balancing market. Ref. [108] reviews changes to the balancing market in France to enhance transparency and competition. Ref. [109] focuses on the DA market in Germany and investigates the impact of offshore wind, and in [110] a brief overview of the functioning of the different German markets is given. Ref. [111] analyzes the implementation of a German discrete ID auction, while discussing the functioning of both auction-based and continuous ID trading. Refs. [112, 113, 114] focus on a variety of design parameters of the German balancing market's procurement side. Ref. [115] analyzes the German balancing mechanism while focusing on the interplay between imbalance pricing and congestion. Ref. [116] discusses three interactions between variable RES and balancing markets, and [117] studies the impact of the balancing market design on the participation of flexible consumption, both with a focus on Germany. Ref. [118] analyzes incentives to behave strategically in the German balancing market, while [119] discusses its design together with historical data. Ref. [120] reviews a general set of principles of the different markets in the Netherlands (NL), but only considers limited design parameters, while in [121] the Dutch balancing market is discussed. Ref. [122] focuses on the procurement side of the Dutch balancing market and the participation of electric vehicles. Turning to discussions of individual market zones outside the CWE region, [123] analyzes the participation of RES in the Spanish ID market, while providing an overview of the Spanish short-term markets. Ref. [124] reviews the Spanish balancing market, and identifies market attributes that may hinder RES participation, while [125] provides an overview of the procurement side of the Spanish balancing market. Ref. [126] provides a general overview of the Nordic short-term markets and analyzes the participation of wind generators, with a focus on the ID market, and [127] provides an overview of the procurement side of the Nordic balancing market.

The second group of studies focuses on design of short-term markets that include multiple market zones. Ref. [128] discusses general principles of the Dutch markets, and of the German ID market, while assessing wind generator bidding strategies. Ref. [11] analyzes negative prices that occasionally occur in DA, ID, and RT markets in Belgium, France, and Germany, and generally describes these markets. In [106], the implementation of flow-based market-coupling (FBMC) in the CWE DA markets is discussed. Ref. [102] analyses DA and ID market liquidity in France, Germany, Scandinavia, Spain, and the UK, while discussing a selection of design attributes. In [129], ID trading activity and prices are analyzed for a variety of market zones in Northern Europe, while also discussing the impact of imbalance settlement rules in the Nordic countries on ID trading. Ref. [130] compares balancing market design parameters across 28 countries in Europe, while [131, 132, 133, 134, 135, 136] include empirical analyses of

ID and RT markets in Germany, Italy, Poland, Spain, the Netherlands, and the UK, respectively. Ref. [137] compares the settlement side of the Dutch, German, and Nordic balancing markets. In [138], a valuable discussion on a variety of design parameters for the three short-term markets is provided, based on observations from Germany, Italy, the Netherlands, Poland, Spain, and the UK, to identify aspects which may benefit from harmonization. In addition, in 2014 the Belgian, German, and Dutch TSOs published a study on potential cross-border cooperation [99], in which the design of their RT balancing markets is discussed. Finally, [139] compares the European DA market design with designs adopted in the US.

The third group of references are not zone-specific, but of a more general focus. In [140] a variety of market design issues for RES integration are discussed, while [141] analyzes the impact of RES support schemes and certain market design parameters on RES integration. Ref. [142] analyzes expected trading volumes in different European ID markets, while the general functioning of continuous and auction-based ID markets is explained. Ref. [143] discusses different design parameters for balancing markets, in order to facilitate wind integration, while [144] identifies important balancing market design parameters for both individual control areas and cross-border cooperation. Finally, [145] assesses different alternatives to allocate cross-border transmission capacity in Europe, and [146] analyzes the impact of imbalance pricing on the behavior of market participants.

Table 4.1: Literature review classification.

	DA market	ID market	RT market
BE	[11], [106]	[11]	[11], [99], [103], [130]
FR	[11], [102], [106]	[11], [102]	[11], [108], [130]
DE	[11], [102], [106], [109], [110], [138]	[11], [102], [110], [111], [128], [131], [138]	[11], [99], [110], [112], [113], [114], [115], [116], [117], [118], [119], [130], [131], [137], [138]
NL	[106], [120], [128], [138]	[120], [128], [135], [138]	[99], [120], [121], [122], [128], [130], [135], [137], [138]
Other	[102], [123], [126], [138], [139]	[102], [123], [126], [129], [132], [133], [134], [136], [138]	[123], [124], [125], [126], [127], [130], [132], [133], [134], [136], [137], [138]

Research gap in market design analyses and contributions

Although the design of short-term markets in the CWE region has been discussed before, previous works focus on individual or a limited selection of (1) design parameters, (2) sequential markets, or (3) geographical market zones. In addition, the extent to which the market design affects the needs for and rewards to flexibility is not considered. An integrated discussion of design parameters, and their interaction with the demand for and supply of flexibility, for all three short-term markets and all four CWE market zones has thus not been provided before. As such, this chapter answers two research questions. First, how are the markets related to flexibility, i.e., the short-term markets, designed in the CWE region? Second, how do these markets express the need for and reward the supply of flexibility? The answers to these research questions provide insight in whether flexibility is treated consistently and appropriately among the different geographical and sequential markets.

Section 4.2 focuses on the DA markets, while Section 4.3 studies the ID markets, and Section 4.4 encompasses the settlement and procurement side of the RT balancing markets. In each section we focus on the key design features and parameters. The structure of the discussion for each parameter is as follows: we first summarize the design for the CWE market zones, and then hypothesize and analyze the implications for flexibility. The intent is to encourage policy-makers to consider market reforms that would facilitate the integration, availability, or valorization of flexibility, and also to contribute to the decision-making of flexibility investors and operators. In addition, at the end of each short-term market's discussion, we provide a summarizing table, and present the trading volume as a share of the consumption for 2012-2015 to give an idea of its size. Finally, Section 4.5 states the conclusions.

4.2 Day-ahead markets

In the DA market, which is a double-sided blind auction facilitated by power exchanges, market players trade hourly and multi-hourly products to adapt their position from the previously held forward and future markets. These positions, resulting in scheduled output profiles, can be adjusted by submitting demand and supply quantity-price bids before DA market closure, which is at noon (12:00 pm) D-1 in the CWE region [147]. The price in a demand bid indicates the highest price a buyer is willing to pay, while the price in a supply bid indicates the lowest price at which a seller is willing to sell. The intersection of the aggregated demand and supply curve determines the market-clearing volume and price. The DA market is based on a pay-as-cleared principle, through which all cleared demand bids in a market zone pay a uniform market-clearing price, while all cleared supply bids in a market zone are remunerated by that same price. In the CWE region the market zones coincide with the countries, except for the German market zone, which includes Germany, Austria, and (part of) Luxembourg. However, there are plans to split the German market zone in 2018 in order to create a separate market zone for Austria [148]. While DA market trading within market zones is not constrained by the internal electric grid, its interaction with neighboring market zones is constrained due to the limited interconnection capacity. As a result, DA prices may differ between market zones when interconnection lines are congested [11, 149]. Since the planned output schedules after gate closure of the DA market may lead to congestion within a zone, the TSO may be required to perform redispatch actions to clear that congestion [150].

In the remainder of this section we discuss the CWE DA markets' order types, temporal resolution, cross-border trading, price cap and floor, and trading volumes.

4.2.1 Day-ahead market order types

The standardized orders in DA markets are limit orders, i.e., hourly offered or requested quantities at a certain price limit. Besides these hourly products, power exchanges may also allow so-called complex orders. In the CWE region these include block orders, linked block orders, and exclusive block orders. Block orders are used to link several hours, whose quantity may differ for each hour, on an all-or-nothing basis. That is, either the bid is matched on all hours or is entirely rejected. The acceptance of a block order depends on its bid price and the volume-weighted average DA price in the hours contained in the block. A linked block order is a block order that is part of a set of multiple block orders that have a linked clearing constraint, while an exclusive block order is part of a set of block orders of which, at most, one can be cleared [9, 151]. Complex orders allow the implicit inclusion of cost nonconvexities and intertemporal links. These include start-up and shut-down costs, ramp rates, minimum load levels, minimum up and down times, and energy buffer dynamics [152]. In addition, they provide a means for more robust bidding under price uncertainty. However, the amount of complex orders is limited per market participant for computational reasons [153].

In addition, the introduction of so-called storage orders is currently being discussed [154]. This market product would require storage operators to provide technical parameters (i.e., stored energy at the start of the delivery day, energy and power bounds, (dis)charge efficiency, and exogenous power flows) and economic parameters (i.e., the price below which charge bids and above which discharge bids may be cleared). Given these parameters, storage participation can be decided upon by the market-clearing algorithm.

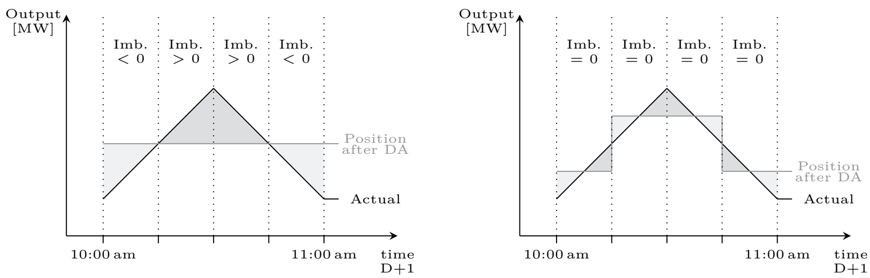
In contrast to block bids, so-called multi-part bids (which are present in some US and European (e.g., Spain) markets) allow players to explicitly include technical and economic parameters in their bids [155, 156, 157]. As block bids require available flexibility to be offered in a standardized format, which may not allow to represent all technological capabilities, we argue that block bidding systems prevent the full available capacity and flexibility from being offered to the market. By allowing current generation, storage, and consumption capacities to formulate their availability more accurately without being restricted by the rigidity of current bid types, part of the future need for flexibility can already be accommodated [138]. In contrast, it has also been argued that a design with a limited number of standardized products may prove more advantageous as transaction costs may be lower, transparency may be higher, and markets may be more easily harmonized and coupled [139]. This is a fundamental debate, and represents a difference in philosophy between what broadly can be called the European and US approaches to DA market design.

4.2.2 Day-ahead market temporal resolution

The DA market is based on hourly market periods, but the settlement period over which market participants are responsible to have a balanced portfolio, are quarter-hourly periods in Belgium, Germany, and the Netherlands, and semi-hourly periods in France. We argue that shorter market periods would allow for an improved alignment with the settlement period, because when market players have the opportunity to trade at a sub-hourly time scale, besides inter-hourly, this allows intra-hourly expected power variations to be dealt with by means of trading in the DA market. While not having this possibility may not be a problem for players with self-balancing capabilities, other (usually smaller) players face the financial risk of being dependent on the TSO to deal with those variations in RT by activating reserves, thereby facing the imbalance price. It is clear that this is especially the case if the ID market is based on hourly market periods as well, or if sub-hourly ID products are characterized by low liquidity.

The illustrative example provided in Fig. 4.1 shows that hourly DA market periods challenge players who face intra-hourly power variations, with limited self-balancing capabilities, to avoid imbalance positions (Fig. 4.1a). While this player has a net balanced position, on average, over the DA market period 10:00 am-11:00 am, imbalances occur in each quarter-hourly imbalance settlement period due to discrepancies between the temporal resolutions. If the DA market period and imbalance settlement period would be aligned, such imbalance positions can be avoided (Fig. 4.1b).

Quarter-hourly intervals would thus shift some of the flexibility demand from the TSO in RT to the DA market, and some of the flexibility supply from self-balancing to the market and from BSPs to DA market participants. As we argue in Section 4.1.2, a finer temporal resolution would also improve the extent to which the value of flexibility for the system is reflected and rewarded, because the resulting price signals would represent the physics of the system more accurately [138, 140]. While a finer temporal resolution would improve the valorization of flexibility in the DA market, its additional value as part of a portfolio compared to standalone flexible capacity might decrease. This can be explained as intra-hourly variations can then also be dealt with through trading, not only through self-balancing using one's own flexible resources.



(a) Hourly DA market. (b) Quarter-hourly DA market.

Figure 4.1: Impact of the misalignment between DA market periods and RT imbalance settlement periods.

All of this leads to the hypothesis that BRPs with limited self-balancing capabilities and TSOs may thus advocate for a finer DA temporal resolution aligned with the imbalance settlement period. Contrarily, challenges may arise for players whose resources are subject to intertemporal links and nonconvex costs, e.g., their start-up cost has to be recovered within the bid of a shorter period. However, the latter counter-argument can be dealt with by the availability of adequate market products to deal with such constraints (i.e., sufficient complex orders, multi-part bidding).

4.2.3 Cross-border trading in the day-ahead market

Through the so-called price coupling of regions (PCR) initiative, 23 European countries[2] are currently coupled through the implicit auctioning of interconnection capacity [158, 159]. This means that all bids of the participating exchanges are considered in the same market-clearing algorithm to optimize the utilization of interconnection capacity available to the power exchanges. Market players

[2]These include Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the UK.

only provide bids for electric energy, while interconnection capacity is allocated implicitly to individual bids to maximize social welfare. As a result, electric energy is exchanged in case of a price difference between geographical markets until the price difference is eliminated or until all available interconnection capacity is used. In contrast, explicit auctioning indicates that interconnection capacity is allocated to individual market players that have obtained the right to use it, after which they can use this capacity to capture price differences between market zones. Such explicit auctioning was the basis for managing limited interconnection capacity prior to the establishment of the European market-coupling-based system [9, 104, 160].

The interconnection capacity available for trade is challenging to determine as electric energy flows according to Kirchhoff's laws, i.e., over all parallel paths in the network, not according to commercial flows, i.e., directly from generator to consumer. In addition, this determination has to make assumptions about the within-zone distribution of generation and consumption. Since May 2015, market-coupling of the DA markets in the CWE region is based on FBMC instead of the Available Transfer Capacity (ATC) method. The ATC value on a border represents the maximum commercial exchange between the two adjacent market zones, taking into account expected market outcomes, security margins, and long-term transmission capacity nominations. The TSOs calculate this ATC value prior to the market-clearing process for each direction on each border of their control areas. In contrast, in the FBMC method, a simplified representation of internal grid constraints, i.e., the collection of critical lines, is included in the market-clearing process. Prior to the market-clearing the TSOs determine the FBMC parameters that define the so-called "FBMC flow domain", in which each boundary refers to the limit of a critical line, while during market-clearing all critical lines are taken into account. In general, FMBC is believed to result in more available interconnection capacity for trade, increased social welfare, and increased price convergence between market zones [106].

Interconnection capacity can either be allocated through PTRs or financial transmission rights (FTRs) via long-term (i.e., yearly and monthly) auctions. At the time of writing, part of the available interconnection capacity at the French-Belgian and Dutch-Belgian borders is allocated through FTRs (since January 2016), while at the Dutch-German and French-German borders this is done through PTRs. A PTR includes the exclusive right to use part of the transmission line. In the CWE region, PTRs are subject to a use-it-or-sell-it principle, which means that if a PTR holder does not actually nominate the corresponding capacity, it is transferred to the power exchange to use in the market-clearing, in addition to the capacity not sold through long-term auctions. In case of a positive price difference between the two market zones in the direction of the PTR, the PTR holder is paid this price difference for all non-nominated capacity. Contrarily, FTRs are financial instruments, so they do not give their holder the exclusive right to use part of the line. All physical capacity subject to the FTRs is transferred to the power exchange, thereby not interfering with optimal market-clearing. What the FTR holder is entitled to is a payment equal to the price difference between the two locations for all transmission capacity subject to the FTR in case of a positive price difference between the two market zones in the direction of the FTR. This use of FTRs is consistent with the US system, where it is believed that separating financial rights from physical operation results in a more efficient use of the grid and hedging of risks [145, 161, 162].

Since variability is spread over a larger area through market-coupling, non-correlated power variations are smoothed and opposite power variations compensate each other. We conclude that this results in lower total flexibility needs. In addition, interconnection capacity is a "vehicle" for flexibility. Flexibility in neighboring areas can be used to compensate for the local system's variability, allowing the sourcing of cheaper flexibility abroad. Alternatively, local flexibility providers have the opportunity to offer services to other regions as well. This reasoning shows that market-coupling thus impacts flexibility demand and supply by enlarging the relevant geographical market to trade flexibility [160].

4.2.4 Day-ahead market price cap and floor

The DA markets in the CWE region include a price cap of 3 000 €/MWh [147]. Such a cap is usually implemented to avoid excessive pricing by generators, especially when the price elasticity of demand is rather low.[3] Although in general price caps should be set at the value of lost load (VOLL) [164] in order to encourage investment in needed peaking plants, they can be set lower if the purpose is market power mitigation. The VOLL represents the average value that consumers attach to a unit of electric energy not supplied, and thus reflects their willingness-to-pay to avoid demand curtailment. Although country-specific estimates are available in the existing literature, and they depend on many specifics (e.g., notification time, duration, time of the day), they are typically between 2 000 €/MWh and 20 000 €/MWh [140, 165]. Because of the large-scale integration of variable RES in the generation mix, conventional power plants currently experience diminishing profitability due to a decreasing number of operating hours and lower electricity prices [103]. The imposed price cap should thus be high enough to allow these conventional power plants to recover their

[3] The price elasticity of demand refers to the relative change in demand due to a relative change in price, and is typically negative, as the demand for most commodities decreases with the price [163].

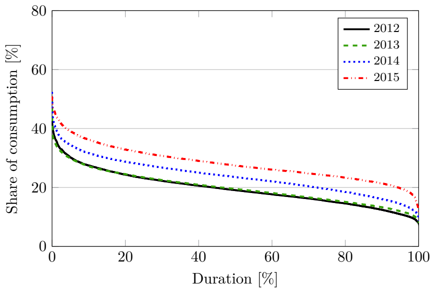
investment cost over a decreased number of operating hours. Although capacity mechanisms are currently also discussed and implemented in the CWE region to ensure generation adequacy [166, 167], such markets are out of the chapter's scope as we focus on flexibility, not adequacy. It is possible for capacity markets to be designed to incent investment and retention of flexible capacity, as in California, but this is not presently done in Europe [168]. Next to system adequacy, we argue that, when set too low, price caps interfere with the market signal representing the scarcity of upward flexibility.

The price floor is set at -500 €/MWh [147]. In contrast to price caps, [140] argues there is no incentive to impose price floors in electricity markets. Negative prices occur when conventional generators are willing to pay to generate in order to avoid costly shut-downs or downward ramping, and when renewable generators are willing to pay up to the subsidies they receive in order to generate [11, 103]. When set too high, we argue that price floors interfere with the market signal representing the scarcity of downward flexibility, and may result in the arbitrary curtailment of generators during excess generation periods, rather than having a pricing mechanism determine who values most being kept on.

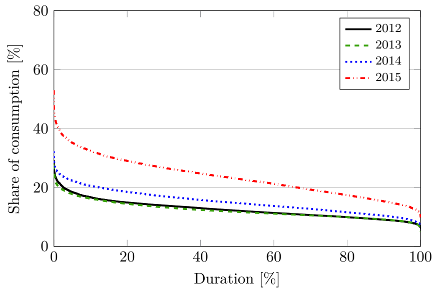
4.2.5 Day-ahead market trading volume and summary

The DA market plays an important role in terms of trading volume. Based on hourly traded volume data from the power exchanges [169, 170, 171], and country-specific hourly consumption data from ENTSO-E [101], Fig. 4.2 shows the hourly traded volume as a share of the hourly consumption for 2012-2015. The trading volume in the German and Dutch market zones represents a larger share of the consumption than that of the Belgian and French market. However, in the latter countries this share has been increasing significantly in recent years, while for Germany it has remained constant and for the Netherlands the share seems to be decreasing.

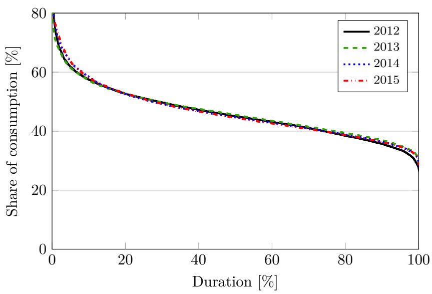
To summarize, Table 4.2 provides an overview of the key characteristics of the DA markets in the CWE region.



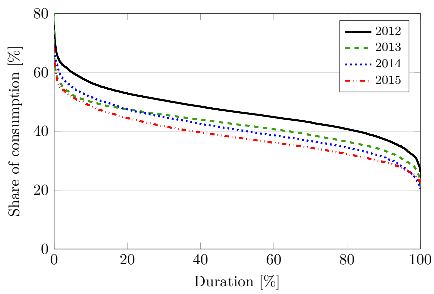
(a) Belgian DA market.



(b) French DA market.



(c) German DA market.



(d) Dutch DA market.

Figure 4.2: Hourly DA market trading volume as share of the hourly consumption, for Belgium (Fig. 4.2a), France (Fig. 4.2b), Germany, Austria, and Luxembourg (Fig. 4.2c), and the Netherlands (Fig. 4.2d).

Table 4.2: Key characteristics of the (fully harmonized) CWE region's DA markets.

	BE	FR	DE	NL
Power exchange	BELPEX	EPEX SPOT	EPEX SPOT	APX
Market closure	12:00 pm D-1	12:00 pm D-1	12:00 pm D-1	12:00 pm D-1
Market period	1 h	1 h	1 h	1 h
Price cap [€/MWh]	3 000	3 000	3 000	3 000
Price floor [€/MWh]	-500	-500	-500	-500
Block orders	✓	✓	✓	✓
Linked block orders	✓	✓	✓	✓
Exclusive block orders	✓	✓	✓	✓

4.3 Intra-day markets

After the DA market-clearing, each BRP is required to submit a balanced position to the TSO for each settlement period. These so-called "nominations" provide information on the planned schedules for every individual unit, and usually differ from the accepted bids in the DA market as they take into account all transactions, including the volumes traded in the previously held long-term markets and through bilateral contracts. However, these nominations can still be adjusted through trade in the ID market based on updated information (e.g., more accurate RES generation forecasts). ID trading is the last opportunity for market-based transactions before submitted schedules become financially binding.[4] After gate closure of the ID market, the TSO takes over the responsibility to keep the system balanced. It is clear that the possibility of ID trading may shift a share of the flexibility needs away from RT to the ID stage, i.e., from the TSO to BRPs, and likewise for the supply of flexibility, i.e., from BSPs to ID market players.

This section discusses the CWE ID markets' market types, order types and temporal resolution, cross-border trading, price cap and floor, and trading volume.

4.3.1 Intra-day market types

While the Belgian, Dutch, and French ID markets are based on continuous trading, the German ID market includes both continuous trading and a discrete auction. With continuous trading, market participants submit supply and demand bids to a central platform, and matching bids are continuously cleared on an individual basis. Continuous trading is possible from 02:00 pm D-1 in Belgium, and from 03:00 pm D-1 in France, Germany, and the Netherlands.[5] This trading can occur until close-to-RT, i.e., until 5 min to RT in Belgium and the Netherlands, and until 30 min to RT in France and Germany. The continuous trading order book is visible to all market participants, and contains all submitted bids that have not cleared yet. In addition, players can cancel submitted noncleared bids at any time. Continuous trading bids are matched according to a price-time priority: orders are matched in order of the attractiveness of their price, with the time of submission to the central platform being a tie-breaker if there are two identical price offers. A continuous trading ID market may thus result in different prices for each trade, with the price being

[4] Submitted schedules are not physically binding, unfulfilled positions (i.e., imbalance positions) are settled at the imbalance price set by the TSO (see Section 4.4.2).

[5] While hourly products can be traded from 03:00 pm D-1 in the German continuous ID market, quarter-hourly products can only be traded from 04:00 pm D-1.

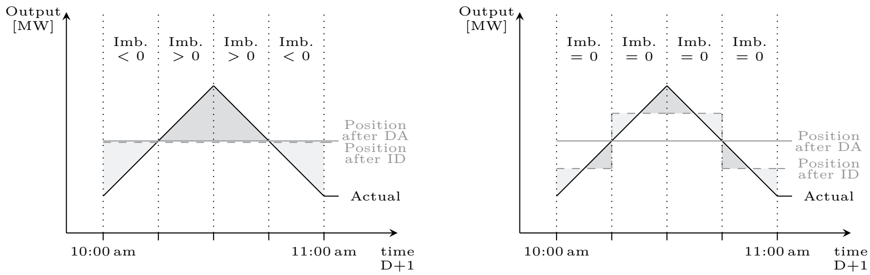
the price of the bid that initiated the match (i.e., the first of the two involved bids, or the "initiator"), which may be referred to as pay-as-bid. The discrete auction implemented in the German ID market since December 2014 is based on principles similar to the DA market. Players submit supply and demand bids, with gate closure at 03:00 pm D-1. These bids are then aggregated to form the supply and demand curve. The intersection determines the uniform market-clearing price [111, 138, 172].

We argue that there are four implications of these designs for flexibility. First, compared to a discrete auction, continuous trading may pose less risk to flexibility consumers and suppliers as they can procure and valorize flexibility immediately instead of having to wait until market-clearing, that is, if there still is a market-clearing to come. Second, when bidding truthfully, nonmarginal flexibility providers may face lower remuneration for their services compared to an auction-based ID market including pay-as-cleared pricing if they are the initiator. Meanwhile, nonmarginal flexibility consumers may satisfy their flexibility need at a higher cost if they are the initiator. Naturally, in such cases the (second-mover) counterparty faces more favorable prices compared to a discrete auction, but risks losing the opportunity to match bids if it waits too long. Thus, continuous trading may incentivize players to not bid truthfully, which may result in incorrect flexibility demand and supply signals. Third, a market based on continuous trading instead of discrete auctions includes a certain first-come-first-serve characteristic, as matching bids are immediately cleared, which may not lead to welfare maximization and optimal allocation of flexibility, especially in illiquid markets. Finally, an important question regarding the organization of ID auctions that is not answered yet includes the optimal number of auctions and their timing, taking into account the impact on liquidity.

4.3.2 Intra-day market order types and temporal resolution

The Belgian, French, and Dutch continuous ID markets include both hourly and multi-hourly (i.e., block) products, while the German ID market also includes quarter-hourly products. In contrast to the DA market, the German ID auction includes 96 quarter-hourly market periods. Block bids have not been introduced yet in that auction [111, 172].

While market participants have the opportunity to update their nominations, which are submitted after clearing of the DA market, on an hourly basis, this does not allow them to tailor output schedules through market-based transactions to the temporal resolution on which their imbalance positions are calculated. The presence of quarter-hourly products in the German ID market provides this opportunity, as players are able to compensate for the misalignment between the DA market periods and RT settlement periods (Fig. 4.3), and incorporate updated information on an intra-hourly basis. As such, players with limited self-balancing capabilities can be less dependent on the TSO to balance their imbalance positions, and are thus less exposed to imbalance prices. Following this reasoning, lower reserve needs are expected for the TSO in RT. Similar to the DA market, we hypothesize that a finer temporal resolution would improve the valorization of flexibility in the ID market due to price signals, but might reduce the additional value of flexibility in a portfolio compared to standalone flexible capacity. This is because intra-hourly variations can now also be dealt with through ID trading, not just through self-balancing.



(a) Hourly or illiquid quarter-hourly ID market. (b) Liquid quarter-hourly ID market.

Figure 4.3: Impact of the misalignment between ID market periods and RT imbalance settlement periods.

4.3.3 Cross-border trading in the intra-day market

In contrast to the DA market, ID markets are currently less well aligned and integrated [138], and no interconnection capacity is reserved for the ID market. Only the residual cross-border capacity is made available to the market. In the CWE region, continuous ID markets are, depending on the considered border, coupled through the explicit or implicit allocation of remaining interconnection capacity, which is calculated according to the ATC method. Here, explicit means that market players can obtain remaining interconnection capacity for free on a first-come-first-serve basis, after which they can engage in cross-border ID trading. If however a player does not use the obtained capacity, this unfulfilled position will be settled (i.e., penalized) at the imbalance price since allocated transmission capacity automatically means nominated capacity [173]. On the other hand, with ID implicit allocation, orders in one zone are automatically matched with orders in the neighboring zone, as long as transmission capacity is available. Unlike explicit cross-border transactions, players do not need to obtain the interconnection capacity before making a transaction. On the Dutch-Belgian border, implicit continuous capacity allocation applies [174], while on the Dutch-German and the French-Belgian border, explicit allocation is in place [175, 173]. Finally, on the French-German border, implicit allocation runs in parallel with explicit allocation, the latter for OTC trading purposes [176].[6]

With continuous trading, the value of the transmission capacity is captured by the first mover in case of explicit auctioning and by the first matching cross-border bids under implicit auctioning. In general, this fails to maximize welfare because the capacity is not necessarily allocated to the most valuable transactions. In addition, this does not provide revenues to the owner of the interconnector (that could be used to lower costs for consumers or incentivize new investments in interconnection capacity), as is the case in the DA market through the sale of transmission rights. In contrast, it has been argued that the use of discrete ID auctions could facilitate the most efficient allocation of the remaining interconnection capacity and remunerate the owner similar to the situation in the DA market [111, 138].

When the ID market is rather illiquid, flexibility consumers may not find a counterparty, and as such become exposed to imbalance penalties, while flexibility suppliers may not be able to valorize their flexibility. It is obvious that this can be dealt with by matching bids over a larger geographical area through cross-border ID trade.

4.3.4 Intra-day market price cap and floor

In the CWE region, the continuous ID market price cap is set at 9 999 €/MWh, and the price floor at - 9 999 €/MWh, which represents a wider range compared to the DA market, while for the German ID discrete auction these price limits are more similar to the DA market at 3 000 €/MWh and - 3 000 €/MWh, respectively. A similar reasoning as for the DA market applies with respect to the rationale behind price limits and their interaction with flexibility.

4.3.5 Intra-day market trading volume and summary

The ID market plays a minor role in terms of trading volume, but it is an important tool to guarantee the reliable operation of the power system: each trade may contribute to a reduction in the activation of reserves by the TSOs. Based on hourly and quarter-hourly traded volume data from the power exchanges, and country-specific hourly consumption data from ENTSO-E,

[6] This is changing rapidly, with an observed transition from explicit to implicit allocation.

Fig. 4.4 shows the traded volume as a share of the hourly consumption for 2012-2015.[7] While for all four market zones the role of the ID market has increased in 2014-2015 compared to 2012-2013, a much larger share of the consumption is traded in the German ID market compared to the other market zones (note that the y-axis of Fig. 4.4c has a different scale). This may result from the fact that Germany experiences larger shares of RES generation, and includes more ID trading possibilities due to the presence of quarter-hourly ID products. The large increase from 2014 to 2015 is in part due to the implementation of the discrete auction in December 2014.

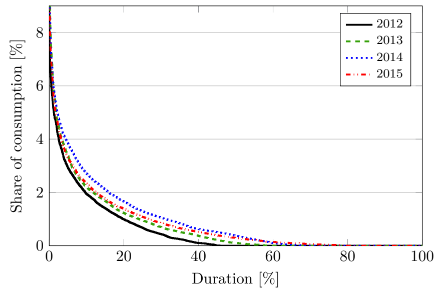
While in 2015 continuous trading remains more important in terms of trading volume in Germany compared to the discrete auction, the latter already represents a nonnegligible share (Fig. 4.5a). In addition, Fig. 4.5b shows that market players seem to have a large interest in quarter-hourly products (i.e., both in the continuous and auction-based ID market), which take a significant share of the trading volume.

Table 4.3 summarizes the major attributes of the ID markets in the CWE region.

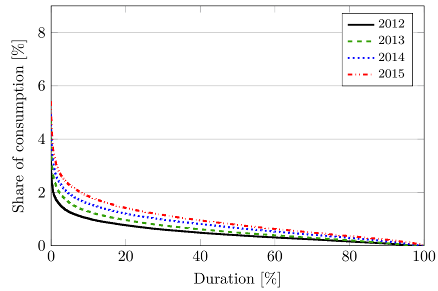
Table 4.3: Key characteristics of the (partially harmonized) CWE region's ID markets.

	BE	FR	DE	DE	NL
Power exchange	BELPEX	EPEX SPOT	EPEX SPOT	EPEX SPOT	APX
Continuous trading	✓	✓	✓	✓	✓
Market opening	02:00 pm D-1	03:00 pm D-1	04:00 pm D-1	03:00 pm D-1	03:00 pm D-1
Market closure	5 min to RT	30 min to RT	30 min to RT	30 min to RT	5 min to RT
Market period	1 h	1 h	15 min	1 h	1 h
Price cap [€/MWh]	9 999.99	9 999	9 999	9 999	9 999.90
Price floor [€/MWh]	-9 999.99	-9 999	-9 999	- 9 999	-9 999.90
Block orders	✓	✓	✓	✓	✓
Discrete auction	✗	✗	✓	✗	✗
Market closure	-	-	03:00 pm D-1	-	-
Market period	-	-	15 min	-	-
Price cap [€/MWh]	-	-	3 000	-	-
Price floor [€/MWh]	-	-	-3 000	-	-
Block orders	-	-	✗	-	-

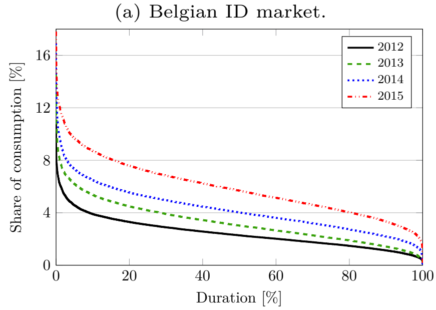
[7] Data for the continuous ID markets in Germany/Luxembourg and Austria are provided together as one market, but they might be disconnected temporarily due to measures performed by the TSOs [177].



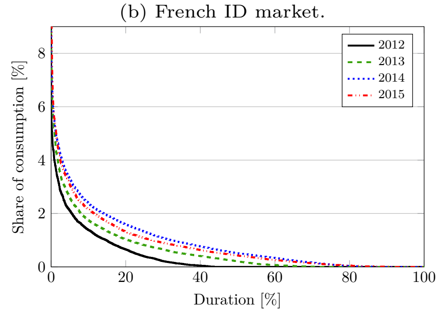
(a) Belgian ID market.



(b) French ID market.

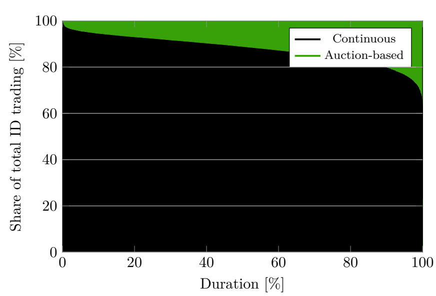


(c) German ID market.

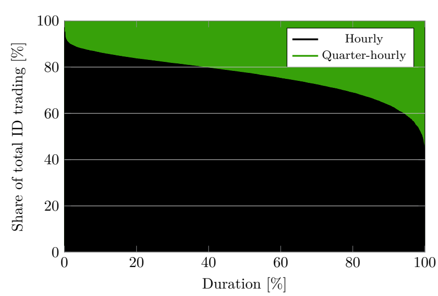


(d) Dutch ID market.

Figure 4.4: Hourly ID market trading volume as share of the hourly consumption, for Belgium (Fig. 4.4a), France (Fig. 4.4b), Germany, Austria, and Luxembourg (Fig. 4.4c), and the Netherlands (Fig. 4.4d).



(a) Continuous vs. auction-based.



(b) Hourly vs. quarter-hourly.

Figure 4.5: Hourly German ID market trading volume (Fig. 4.5a) continuous vs. auction-based trading, and (Fig. 4.5b) hourly vs. quarter-hourly products, both expressed as share of the total ID trading, 2015.

4.4 Real-time balancing markets

After gate closure of the ID market, unforeseen differences between scheduled and actual generation or consumption may occur. These differences may originate from (1) unexpected RES generation variations, (2) unexpected consumption variations, (3) unplanned outages of generation and consumption capacity, and grid elements, (4) discrepancies between the duration of DA/ID market periods and RT settlement periods, and (5) the discretization of continuous time in discrete market periods [113].

These events are dealt with in RT by the balancing market, which is coordinated by the TSO. First, the TSO calculates the total SI, i.e., the demand for flexibility in RT, resulting from the aggregated individual imbalances of BRPs. The TSO then compensates for this SI by activating reserves, i.e., the supply of flexibility in RT, that may have been contracted ahead of time from market participants who provide balancing services, i.e., BSPs. In general, this demand for the activation of reserves is rather small compared to the system load, and is highly volatile and price inelastic as well [117]. The reservation and activation of reserve capacity is referred to as the procurement side of the balancing market. Afterwards, the TSO settles individual imbalances with BRPs by applying imbalance prices to their imbalance positions. This is referred to as the settlement side of the balancing market. BRPs thus "trade" balancing energy with the TSO, which in turn procures these services from BSPs [103, 113, 143]. BRPs can also deal with unexpected power variations by activating flexibility in their own portfolio instead of relying on the TSO to provide flexibility at the settlement side of the balancing market.

4.4.1 Control areas

Belgium, France, and the Netherlands each consist of one control area, each managed by one TSO, i.e., Elia, RTE, and TenneT, respectively [121]. In contrast, Germany includes four control areas, each being operated by its own TSO: Amprion, 50 Hertz, TenneT, and TransnetBW. The German TSOs cooperate to keep their control areas balanced through the so-called Grid Control Cooperation (GCC). The GCC includes four modules that were introduced one after the other, and focuses on aFRR, i.e., secondary control.[8] The objective of the first module, imbalance netting, is to reduce the total activation of reserve capacity by avoiding counteracting activations. The second module includes a common reserve sizing and access to reserve capacity in other control zones in case of a local shortage. The third module procures reserves using a common

[8] The different reserve categories are described in Section 4.4.3.

market, i.e., bids are accessible to all TSOs. The implementation of the fourth module leads to a common merit-order for the activation of reserve capacity in order to activate the cheapest bids, respecting limits on the connecting transmission lines [113, 119, 178]. In contrast, the activation of mFRR, i.e., fast tertiary control, is currently still done in a decentralized way, but is based on common rules. This advanced inter-TSO cooperation also includes a single imbalance price over the different control zones, whose calculation is discussed in Section 4.4.2. We conclude that such cooperation is likely to provide similar benefits as market-coupling in the DA and ID market, and similar impacts on the need for and supply of flexibility.

4.4.2 Settlement side

At the settlement side of the balancing market, the BRPs' imbalance positions and the imbalance prices are determined. As stated before, BRPs have to submit nominations for planned grid-exchanges on the plant-level to the TSO after DA market-clearing, and again after transactions in the ID market. Although this detailed plant-level information has to be reliable in order for the TSO to effectively analyze congestion on the internal grid of its control area, there is no incentive for BRPs to do this on a plant-level, since they can only be held accountable for imbalance positions aggregated over their portfolio. Although it has not been quantified to which extent this may be a problem, a requirement for plant-level balance responsibility might ensure that TSOs receive more reliable information [138].[9]

A BRP's imbalance position is the difference between the nominated position after closure of the ID market and the actual net exchange of electric energy with the grid in RT. During each settlement period, a BRP can have a long, short, or balanced position. A long position indicates a positive imbalance, thereby injecting more and/or withdrawing less than planned. A short position indicates a negative imbalance, in which the BRP injects less and/or withdraws more than planned. Both long and short imbalance prices have to be determined by the TSO. BRPs with a long position in RT receive the long imbalance price, while BRPs with a short position in RT pay the short imbalance price [146].

Through the imbalance settlement, the TSO allocates the activation cost of reserve capacity (in €/MWh) to responsible BRPs, while reservation costs (in €/MW) associated with contracting reserves are recovered through grid tariffs. Imbalance prices are available shortly after RT in Belgium, France, and the Netherlands, while German imbalance prices are only published a few weeks after delivery [99, 130]. As the former provides BRPs with valuable market

[9] But this might have disadvantages as well.

information soon after RT, which can be used to make informed decisions with respect to their portfolio, we hypothesize that BRPs prefer this to the latter.

In the remainder of this section we discuss the settlement side's temporal resolution, pricing rules, and price cap and floor.

Imbalance settlement temporal resolution

The Belgian, Dutch, and German balancing markets are based on quarter-hourly market periods, while semi-hourly periods are used in France [130]. Since imbalances vary on a continuous basis, instantaneous imbalance positions of BRPs differ from measured net imbalance position over the settlement period. As BRPs are only held accountable for the net imbalance position over a period, players that caused large instantaneous imbalances, and thus the activation of additional reserves, may not be charged for the costs they have caused. As this issue is related to intra-settlement period imbalances, it is expected to occur less with shorter settlement periods [20]. These provide an incentive to BRPs to keep their portfolio balanced on shorter time frames, thereby most likely increasing the demand for flexibility by BRPs, either as part of their portfolio or by means of ID trading, which in turn would lower the flexibility needs of the TSO in RT.

Single-pricing vs. dual-pricing

Imbalance prices can either be calculated through a dual or single-pricing scheme. In a dual-pricing scheme, the imbalance price applied to BRPs' imbalance positions in the same direction as the SI is based on the activation cost of reserve capacity, while the imbalance price applied to BRPs' imbalances in the opposite direction of the SI is typically based on the DA price. In contrast, within a single-pricing scheme, a uniform imbalance price, based on the activation cost of reserve capacity, is applied to all BRPs having an imbalance position [103, 113, 143].

In France a dual-pricing scheme is applied,[10] while the calculation of the imbalance price in Belgium, Germany, and the Netherlands is each based on a single price that applies to all imbalances [103, 130]. However, the imbalance pricing scheme in the Netherlands is not a pure single-pricing mechanism, since in case both up and downward reserves are activated the prices differ: the long imbalance price equals the marginal activation price for downward reserve while the short imbalance price is the one for upward reserve [172].

[10] The French imbalance pricing mechanism changed in April 2017 [179]. Nevertheless, this chapter's insights in single-pricing vs. dual-pricing are valid independent from the considered geographical market zone.

In addition, in Belgium and the Netherlands, the imbalance price applied to short and long positions differs in the event of large imbalances, thereby moving from a single to a dual-pricing scheme. This is done by including a balance-incentivizing component, to either punish BRP imbalances in the same direction as the SI or to incentivize all BRPs to keep their balance. Although such a component is applied in Germany as well, it does not result in different short and long imbalance prices. The imbalance price is increased for all BRPs if the system is short, and decreased for all BRPs if the system is long [119]. In France, the imbalance price applied to BRP imbalances in the direction of the SI is adjusted by a multiplier $1 + K$, set at 1.08 since July 2011 [180].

To lessen the need for activation of reserve capacity on the procurement side of the balancing market, BRPs can help the TSO keep the system balanced by intentionally incurring imbalance positions in the opposite direction of the SI, which can be referred to as “passive balancing” [181]. However, we argue that with dual-pricing there is unfortunately little incentive to provide passive balancing since the DA price is applied to imbalances in the opposite direction of the SI. In contrast, single-pricing schemes incentivize BRPs to perform passive balancing. The reasoning for this proposition proceeds as follows.

- In case of a negative SI, the TSO activates upward reserve. Typically, this is activated at a higher price compared to the DA price, and a larger quantity of activated upward reserve results in a higher imbalance price, as it is typically selected according to a merit-order of increasing activation prices. This incentivizes BRPs to have a long position.
- In case of a positive SI, the TSO activates downward reserve. Typically, this is activated at a low price compared to the DA price, and a larger amount of activated downward reserve results in a lower imbalance price, as it is typically selected according to a merit-order of increasing activation prices from the TSO point of view, i.e., decreasing resulting imbalance prices when considering downward reserve capacity. This incentivizes BRPs to have a short position.

However, some regulators prefer a dual-pricing scheme (e.g., France), as this avoids BRPs to be incentivized to speculate on the direction of the SI [20]. In addition, in Germany BRPs are contractually not allowed to deviate from their nominated position to benefit from favorable imbalance prices, even though that might help the system [138]. Instead, both countries rely solely on the TSO to balance the system by activating reserve capacity, which can be justified in two ways. First, deviations based on passive balancing are not communicated to the TSO, which makes congestion management difficult due to the lack of reliable information. Second, forecasts of different players on whether to incur a long or short position for passive balancing are often based on similar algorithms. In case the algorithms suggest the wrong direction, the need for balancing services would be further increased, while when multiple BRPs provide such passive balancing and their forecasts about the system state is correct, they may turn oversupply into undersupply situations and vice versa, instead of decreasing the absolute value of the SI. In contrast to Germany where this is not allowed, and to France where the dual-pricing scheme does not provide an incentive, in Belgium and the Netherlands passive balancing is possible and allowed. Those countries believe that such behavior can serve a valuable social purpose and contributes to the valorization of flexibility.

Finally, it has to be noted that in Belgium, Germany, and the Netherlands, BRPs can still change their submitted nominations after gate closure of the ID market, even after RT, by means of a so-called OTC "day-after" market [99, 130]. This trading of individual BRP imbalances has no physical meaning, but changes the accounting in the settlement process. The volume traded in this market is small (or negligible) if market participants have an idea of the level of imbalance prices, as there are no win-win situations in case of single-pricing. In case the imbalance price is positive, the player with a long position is not willing to lose its long position since he receives the imbalance price. Meanwhile, in the case in which the imbalance price is negative, the player with a short position receives an income because of its imbalance as he pays the imbalance price. In Germany, day-after trading can reduce the uncertainty until the imbalance price is known a few weeks after delivery. However, as shown in [118], there is a high predictability of the approximate level of imbalance prices, rendering this market largely irrelevant in Germany as well [116, 119].

Marginal pricing vs. average pricing

When the imbalance price reflects the procurement cost of the activated reserve capacity, it is either based on the marginal or average activation price [103, 113, 143]. With marginal pricing, the imbalance price is set to the price of the marginal accepted bid, while for average pricing the imbalance price is calculated by dividing the net total activation costs of the TSO by the net activated reserve volume. The imbalance price is based on marginal pricing in Belgium and the Netherlands, while France and Germany apply average pricing [115, 117, 130, 146].

In general, there is a widely held view that marginal pricing provides BRPs with more accurate signals into the cost to cope with their imbalances, and as such gives a greater incentive to avoid imbalance positions [20, 117]. Since in single-pricing schemes it may be profitable for BRPs to deviate from their submitted schedules for passive balancing, it is clear that profits would rise with more extreme imbalance prices. Marginal pricing leads to more extreme prices compared to average pricing in case of TSO balancing actions in one direction, while in situations where the TSO activates both up and downward reserve capacity this may not always be true. However, with average pricing, the imbalance price is often capped by the marginal activation price (e.g., Germany). Therefore, we conclude that marginal pricing may be preferred by BRPs wishing to perform passive balancing actions, while average pricing appears to be advantageous for BRPs having limited access to flexible resources to avoid the risk of being exposed to more extreme (unfavorable) imbalance prices.

Imbalance price cap and floor

The imbalance price in the Belgian RT balancing market includes a price cap of 3 000 €/MWh, and price floor of - 3 000 €/MWh. Contrarily, the Dutch imbalance price is less heavily bounded, with a (theoretical) price cap and floor of 100 000 €/MWh and - 100 000 €/MWh, respectively [121]. The German imbalance price is, after calculation according to the average pricing principle, limited by the marginal activated up and downward reserve bid. Afterwards, this capped price is compared to the average volume-weighted ID price. In case the net regulation volume (NRV) is positive (i.e., SI is negative), the ID price represents a lower limit, while if the NRV is negative (i.e., SI is positive), the ID price represents an upper limit. Any remaining reserve activation costs that are not covered by the settlement mechanism are recovered through grid fees together with the reservation costs to contract reserve capacity [115]. In France, if the SI is positive, the imbalance price for BRPs with a long position is capped by the DA price, while if the SI is negative, the imbalance price for BRPs with a short position must at least equal the DA price [180]. High imbalance prices are market signals that represent a relative scarcity of cheap upward flexibility when facing negative SIs, while negative imbalance prices signal the scarcity of cheap downward flexibility with positive SIs [103].

4.4.3 Procurement side

At the procurement side of the balancing market, the TSO procures and activates reserve capacity from BSPs.[11] Besides the distinction between up and downward reserve, ENTSO-E further categorizes reserve capacity into three groups. FCR,

[11] We focus on frequency control, as other grid services (i.e., black-start capabilities, voltage support, and congestion management) are not within the scope of this chapter.

i.e., primary control, is activated automatically in a matter of seconds, in response to frequency deviations for the entire synchronous zone, and needs to have the ability to be fully operational in 0.5 min. FRR is either activated automatically (aFRR), i.e., secondary control, or manually (mFRR), i.e., fast tertiary control, and restores the system frequency by restoring the balance in the control zone, thereby relieving the activated FCR. Its activation is triggered by the ACE, which is calculated as the difference between the scheduled and actual power interchange of a control area. While aFRR capacity needs to be fully operational in 5-15 min, for mFRR capacity this is in 7.5-22.5 min, both depending on the control zone. Finally, RR, i.e., slow tertiary control, can be used to support or relieve the activated FRR. RR is not further discussed as it is currently not used by the Belgian, German, and Dutch TSOs. Instead, they expect BRPs to already offset part of their imbalances by means of self-balancing and trading on the ID market [29, 99].

In what follows we discuss the procurement side's reserve remuneration, contract periods, selection and activation mechanism, cross-border cooperation, and market size.

Reserve remuneration

In general, BSPs providing FCR only receive a reservation payment. This is because no activation payment applies since up and downward FCR activations are expected to compensate each other and only represent very small volumes [118, 143]. However, this is not the case in France, where the DA price serves as proxy for activation payments [182]. For contracted aFRR and mFRR, both reservation and activation payments apply.

Payments are either based on a fixed regulated price, pay-as-bid pricing, or pay-as-cleared pricing.[12] The reservation of FCR is remunerated pay-as-bid in Belgium, Germany, and the Netherlands, and through a regulated price in France. Both the reservation and activation remuneration of aFRR is pay-as-bid in Belgium and Germany, while in the Netherlands pay-as-bid applies to the reservation and pay-as-cleared to the activation. In France the provision of aFRR is remunerated by means of regulated prices. For mFRR the reservation is remunerated pay-as-bid in all market zones except for France, where a regulated price applies, while the activation is remunerated pay-as-bid in Belgium, France, and Germany, and pay-as-cleared in the Netherlands [113, 130, 146, 183].

We identify several reasons for the presence of reservation payments. First, in the case of FCR, a reservation payment is needed since usually no activation

[12] For a discussion on the different pricing rules in reserve markets, we refer the reader to [113].

payments apply. Second, reservation costs compensate BSPs' opportunity costs to keep the contracted capacity available. Third, they lower a BSP's risk by yielding a guaranteed income, instead of having to rely on non-guaranteed activations. Fourth, they may contribute to efficient dispatch in the presence of cost nonconvexities. Fifth, capacity payments may be a means to recover costs in case BRPs cannot pass on all of their costs via activation bids because of price limits [143]. In contrast, the main disadvantage of reservation costs is the difficulty in accurately allocating them to responsible BRPs, as they are currently just spread over all system participants through grid fees.

Reserve contract periods

Recently, there has been a move from long-term contracting to more frequent tenders for shorter durations. Currently, FCR is contracted on a weekly basis in Belgium, the Netherlands, and Germany, while aFRR is contracted for the duration of a year in the Netherlands, and a week in Belgium and Germany. While mFRR is contracted for the duration of a year in the Netherlands, and in Belgium both monthly and yearly contracts apply, in Germany daily tenders are organized for six 4 h periods. In France, the provision of FCR, aFRR, and mFRR is mandatory [99, 117, 130, 183]. Next to contracted reserves, in Belgium and the Netherlands (for aFRR and mFRR), and in France (for mFRR), noncontracted voluntary bids are allowed until close-to-RT. In contrast, the German TSOs only consider contracted reserves [99].

We identify four advantages of shorter contract periods. First, they allow TSOs to size reserve needs more accurately for the upcoming period. This may lead to lower total reserve needs, as with longer periods reserve requirements may be oversized for part of the period subject to the sizing. Second, when considering the supply of flexibility, shorter periods allow BSPs to better estimate their opportunity cost and thus more accurately price their service [116, 184]. Third, they also lower the availability risk for BSPs, decreasing entry barriers and fostering competition. Fourth, shorter contract periods allow to more often and accurate arbitrage between different services, thereby improving the allocation of resources to the most profitable ones at each time step. In contrast, we identify two arguments against more frequent tender periods. First, financing new investments in flexibility requires accurate expectations of (future) revenue streams, which is easier with longer contract periods. Second, TSOs may prefer longer contract periods as this guarantees the access to sufficient reserve capacity for a longer period of time [185].

Reserve selection and activation mechanism

FCR is contracted according to a merit-order of increasing prices in the Netherlands and Germany, starting with the lowest, and is co-optimized together with aFRR in Belgium to minimize total combined reservation costs. The latter allows BSPs to better deal with short-term operating constraints. In the Netherlands, aFRR is contracted such that its reservation cost is minimized, which may include an overshoot since bids may not be fully divisible. This may lead to situations where the lowest bid is not necessarily always selected first. An identical approach applies to the reservation of mFRR in both Belgium and the Netherlands. In contrast, in Germany aFRR and mFRR are reserved according to a merit-order of increasing prices, with the lowest bid selected first [99].

While the reservation of reserve is based on the reservation price, the activation of reserve is based on the activation price. While contracted aFRR is activated simultaneously and pro rata in Belgium and France, it is activated sequentially according to a merit-order in the Netherlands and Germany. In contrast, mFRR is subject to a sequential merit-order activation in all market zones. It is important to note that while contracted aFRR is activated pro rata in Belgium, noncontracted aFRR is subject to merit-order activation [99, 130, 186]. In general, pro rata activation inherently results in a more flexible reserve portfolio, but as all contracted sources are activated every time the reserve product is activated, we argue that this can pose a barrier to BSPs operating so-called limited energy resources that prefer infrequent activations.

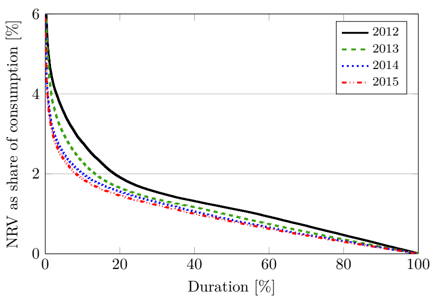
Cross-border reserve procurement

Given the full harmonization of DA markets in the CWE region, and plans for increasingly coupled and harmonized ID markets, the next logical step would involve the RT markets. Although some initial steps have already been taken in this direction, much more work is required. In 2012, the TSOs from multiple neighboring countries, among which TenneT NL and Elia, joined the first module of the GCC, leading to the international GCC (IGCC) [103]. Besides this, TenneT NL (2014) and Elia (2016) joined the existing FCR common procurement platform of the German, Austrian, and Swiss TSOs, for a share of their FCR obligations [138]. The participation of RTE is planned for 2017. Further international integration, along the line of all four GCC modules of the German TSOs (see Section 4.4.1), is expected to result in less total reserve activations, more efficient sizing, and the reservation and activation of the most efficient bids across all participating zones.

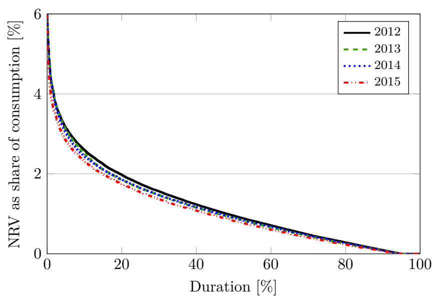
4.4.4 Real-time market size and summary

Based on RT market data from the TSOs [100, 180, 187, 188], and consumption data from ENTSO-E, Fig. 4.6 shows the NRV as share of the consumption for 2012-2015. In general, this share has been decreasing in recent years. We explain this as follows: improved RES forecast accuracy, better profiling in the DA and ID market, increased liquidity in the ID market, increased international cooperation, and increased passive balancing by BRPs. We argue that TSOs may further incentivize the latter by reacting slower to SIs, thereby temporarily keeping the SI at a higher level to attract additional passive balancing.

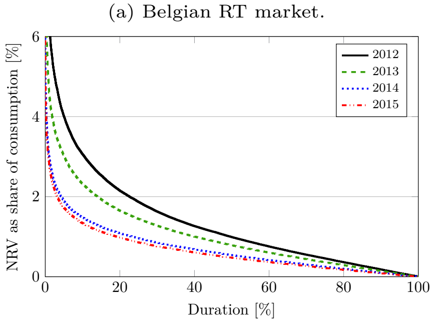
Table 4.4 gives an overview of the key characteristics of the RT markets in the CWE region.



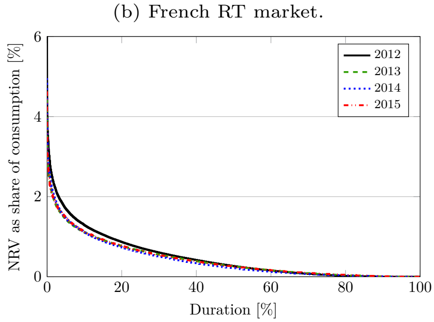
(a) Belgian RT market.



(b) French RT market.



(c) German RT market.



(d) Dutch RT market.

Figure 4.6: Quarter-hourly NRV as share of the quarter-hourly consumption, for Belgium (Fig. 4.6a), France (Fig. 4.6b), Germany (Fig. 4.6c), and the Netherlands (Fig. 4.6d), for the period 2012 - 2015.

Table 4.4: Key characteristics of the (mostly nonharmonized) CWE region's RT balancing markets.

		BE	FR	DE	NL
General	Control areas	1	1	4	1
	TSO	Elia	RTE	50 Hertz, Amprion, TenneT, TransnetBW	TenneT
	Market period	15 min	30 min	15 min	15 min
Settlement	Pricing	Single	Dual	Single	Single
	Pricing	Marginal	Average	Average	Marginal
	Price limits	±3 000 €/MWh	DA price	Marginal activated bids, ID price	±100 000 €/MWh
Procurement	FCR contract period	Weekly	Mandatory	Weekly	Weekly
	FCR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	FCR activation	-	Regulated	-	-
	aFRR contract period	Weekly	Mandatory	Weekly	Yearly
	aFRR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	aFRR activation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-cleared
	mFRR contract period	Monthly/yearly	Mandatory	Daily (4 h)	Yearly
	mFRR reservation	Pay-as-bid	Regulated	Pay-as-bid	Pay-as-bid
	mFRR activation	Pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-cleared

4.5 Conclusions

In the CWE region, the need for and valorization of flexibility in electric energy supply and demand is primarily expressed in the short-term markets, defined as those taking place from the DA stage until delivery, including DA, ID, and RT markets. Due to the ongoing integration of variable RES, the variability in the system is increasing, making these markets increasingly important to keep the system balanced at different time scales. A good understanding of their design, as well as of new developments, is essential for analyses of the need for and supply of flexibility. This chapter therefore provides a detailed overview of the design of the three short-term markets for the four market zones of the CWE region, while focusing on their interaction with flexibility.

Considering the DA market, we discuss its general functioning, and review its specific features, including available order types, temporal resolution, cross-border trading, and price caps and floors. For the ID market, a similar set of topics is considered, while also discussing the difference between its two market types, i.e., discrete auctions and continuous trading. Finally, RT balancing markets include both an imbalance settlement and reserve procurement side. Considering the former, we analyze how the BRPs' imbalance positions and the imbalance prices are determined, while for the latter, we investigate how the TSO procures, activates, and remunerates reserve capacity from BSPs.

While other potentially desirable reforms can be identified when considering the implications for flexibility discussed throughout this chapter, we conclude that policy-makers should focus on four design improvements. The first one is the temporal resolution. As BRPs are only held accountable for the net imbalance position over a settlement period, and not for instantaneous imbalances, quarter-hourly settlement periods in the French RT market would increase the extent to which BRPs are charged for the reserve activation costs they cause. In addition, the introduction of quarter-hourly products in the Belgian, French, and Dutch continuous trading ID markets would allow players to align hourly DA output schedules through market-based transactions to the temporal resolution of the imbalance settlement, and improve the extent to which capacity is rewarded for its flexibility. The second recommended improvement is the introduction of an ID auction for Belgium, France, and the Netherlands. As the impact on liquidity needs to be taken into account, further integration of the CWE ID markets through market-coupling naturally follows, which would also promote an efficient allocation of flexibility and interconnection capacity. Third, as passive balancing can serve a valuable social purpose and improve the valorization of flexibility, incentivizing design changes should be considered for the French and German balancing markets. Fourth, more cross-border inter-TSO cooperation should be promoted on the procurement side in the CWE region's balancing markets, similar to the cooperation of the four German TSOs. Such cooperation is expected to contribute to more efficient reserve sizing, reservation, and activation.

In terms of relative size of the three markets, trading volume analyses show that the DA market is an important market in the CWE region. In 2015, it comprised on average 28.19 % (BE), 23.48 % (FR), 46.21% (DE), and 38.47 % (NL) of the hourly consumption. Although the ID market still plays a minor role in terms of trading volume, i.e., in 2015 on average 0.81 % (BE), 0.94 % (FR), 5.90% (DE), and 0.83 % (NL) of the hourly consumption, these volumes have been increasing steadily over the past few years, and are expected to keep on growing. In Germany the ID market is relatively large due to the demand for ID flexibility resulting from high RES penetrations, and because of its relatively sophisticated market design including both continuous trading and a discrete auction, and both hourly and quarter-hourly products, all of which facilitate trade. Finally, the RT balancing market's size, measured in terms of the NRV, has seen its share of consumption decrease from 2012 to 2015, with average shares falling from 1.33 % to 0.95 % (BE), from 1.19 % to 1.05 % (FR), from 1.38 % to 0.63 % (DE), and from 0.49 % to 0.44 % (NL). This can be attributed to more accurate RES generation forecasts, improved profiling in the DA and ID market, increased liquidity in the ID market, increased international cooperation, and increased passive balancing by BRPs.

We conclude that the details of market design are crucial to the successful integration of variable RES, as they determine the rules by which flexibility providers must play, and define the opportunities for these sources to valorize flexible operations.

Chapter 5

Single-application operation

Price-based unit commitment electricity storage arbitrage with piecewise linear price-effects

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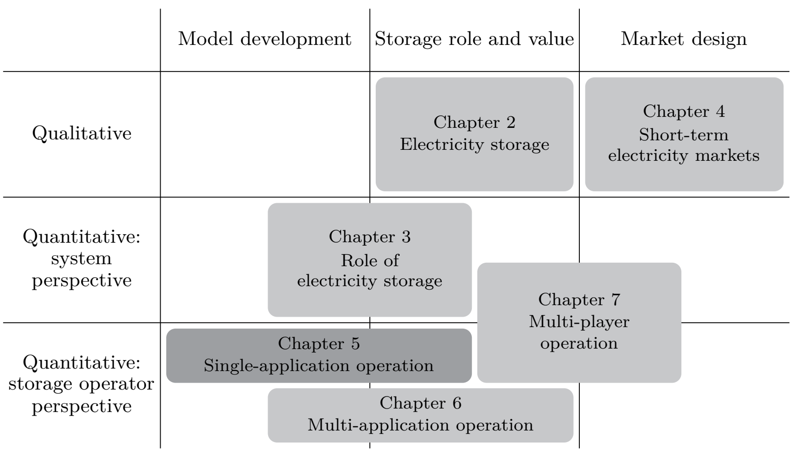
The first author is the main author of this article. The contributions of the first author include the literature study, the co-development of the models, the software implementation in MATLAB and GAMS, the co-analysis and co-interpretation of the results, and the writing of the manuscript. The second, third, fourth, and fifth author provided help and guidance in the development of the models, and in the analysis and interpretation of the results. A preliminary version of this article is published as a DIW Berlin Discussion Paper [189].

Abstract:

Electricity storage plants can be used for many applications, with one of the most studied applications being arbitrage in the day-ahead market. Although the arbitrage value is related to the presence of price spreads, it also depends on the effect of (dis)charge actions on prices, as arbitrage generally reduces price spreads by increasing off-peak prices when charging and decreasing peak prices when discharging. As such, there are two important assumptions in price-based unit commitment arbitrage models: first, whether the storage operator is

assumed to have perfect knowledge of future prices, and second, whether they recognize that their (dis)charge actions may affect those prices, i.e., the price-taking or price-making assumption. This chapter proposes a comprehensive formulation of the arbitrage problem including detailed operating constraints, and focuses on relaxing the price-taking assumption by considering real-world price-effect data, published in the form of hourly piecewise linear relationships between quantity and price based on submitted bids, which are referred to as “market resilience functions”. These can be used to (1) evaluate the price-taking and price-making assumptions based on simplified price-effects, and to (2) provide an upper limit to the arbitrage value under the assumption that prices and price-effects are known at the decision stage. In addition, a stepwise approximation to the piecewise linear functions is developed to reduce computation time, i.e., from mixed-integer nonconvex quadratic programming to mixed-integer linear programming, while providing lower and upper bound approximations to the arbitrage value. The developed models are applied to the Belgian day-ahead market for 2014, and show that the price-effect has a strong impact on the operation and arbitrage value of large-scale storage.

Positioning:



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5.1 Introduction

5.1.1 Motivation

The storage of electricity represents a combination of three functions [3]: consuming electricity, accumulating the energy in some form, and generating electricity. Only part of the consumed electric energy is converted to energy stored in the buffer during charging because of a charge efficiency $0 < \eta^{\mathrm{c}} \leq 1$, while only part of the stored energy is converted back into electric energy during discharging because of a discharge efficiency $0 < \eta^{\mathrm{d}} \leq 1$. The buffered energy may also increase and decrease independent of the grid through exogenous power flows $p_t^{+} \geq 0$ (addition) and $p_t^{-} \geq 0$ (removal), e.g., water inflow and evaporation in the upper reservoir for PHS plants. The general power balance of storage plants that consume electric power $p_t^{\mathrm{c}} \geq 0$ and generate electric power $p_t^{\mathrm{d}} \geq 0$, and store it in an energy buffer $e_t \geq 0$, is then:

$$\underbrace{\frac{de_t}{dt}}_{\triangle\text{ Energy buffer}} = \underbrace{\underbrace{p_t^{\mathrm{c}} \cdot \eta^{\mathrm{c}}}_{\text{Addition}} - \underbrace{p_t^{\mathrm{d}} / \eta^{\mathrm{d}}}_{\text{Removal}}}_{\text{Electric origin}} + \underbrace{\underbrace{p_t^{+}}_{\text{Addition}} - \underbrace{p_t^{-}}_{\text{Removal}}}_{\text{Exogenous origin}} . \tag{5.1}$$

In recent years there has been a renewed interest in electricity storage due to the liberalization of electricity markets and the integration of variable RES. Their expected and unexpected variability results in an increased need for flexibility, which is the ability to provide power adjustments to deal with temporary imbalances between generation and consumption of electric energy [190, 191]. Electricity storage plants can provide this flexibility by charging and discharging through interaction with an energy buffer. However, flexibility can also be provided by flexible generation and consumption, and by the electric grid through which flexible capacity in neighboring regions can be accessed (Fig. 5.1). Market participants are only incentivized to integrate new flexible resources when the investment is profitable. Although electricity storage plants can be used for many applications (e.g., arbitrage, portfolio management, frequency control, voltage support, black-start service [10, 25]) and maximizing the value of storage requires the aggregation of different applications, one of the most studied and well-known applications is arbitraging DA market electricity prices [192, 193]. This chapter focuses on the arbitrage application as the sole revenue source.

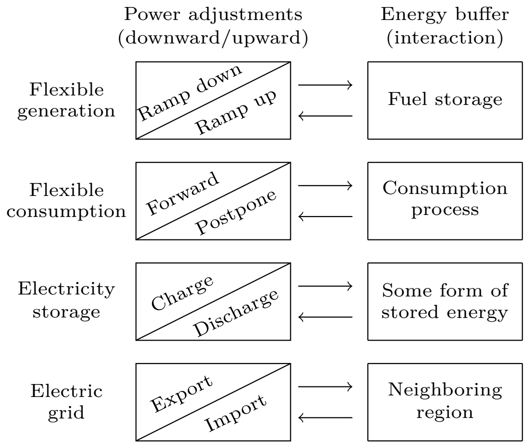


Figure 5.1: Overview of power system flexibility sources.

5.1.2 Scope and approach

Classic definitions of arbitrage denote making a riskless profit by simultaneously buying and selling a similar commodity with net zero investment. However, in a broader context any activity in which a player buys a commodity at a relatively low price and sells a similar commodity, or commodity in which the former can be converted, at a relatively high price for profit can be referred to as arbitrage. This broader definition allows to include initial investments, does not require simultaneity of the purchase and sale, and furthermore does not require a single commodity either (i.e., so-called intercommodity arbitrage) [28]. In the context of this chapter, arbitrage is defined as the capturing of price spreads over time in a single market, being the DA market, by means of electricity storage plants. Although the arbitrage value is directly related to the presence of these price spreads, it also depends on the price-effect of (dis)charge actions, as additional storage capacity generally reduces price spreads by increasing off-peak prices when charging as well as decreasing on-peak prices when discharging.

In contrast to cost-based UC, which refers to the scheduling of generation capacity to meet system load at minimum cost, the single-player self-scheduling problem with the objective to maximize profit based on price signals is referred to as PBUC [194]. The arbitrage application is widely discussed in the literature, both from a system perspective (e.g., [195, 196, 197, 198, 199, 200]) and from an individual storage plant's PBUC perspective, the latter being the focus of this chapter. Generally, there are two important assumptions in PBUC arbitrage models: the first is related to the storage operator's assumed knowledge of future prices, i.e., the (im)perfect price foresight assumption, while the second is related to whether they recognize that their (dis)charge actions may affect those prices, i.e., the price-taking or price-making assumption [201, 202].[1]

A large share of the existing PBUC work assumes perfect foresight of future prices, and no price-effect with the storage plant to be a price-taker: i.e., it is small enough to not affect prices, or its price-taking participation is already included in the prices (e.g., [203, 204, 205, 206, 207, 208]). Reference [203] provides an estimate of the arbitrage value in 14 deregulated markets, [204] considers the Danish market, [205] analyzes the arbitrage value in the PJM, ERCOT, and CAISO markets in the US, [206] considers different markets in the US and compares them with the UK, Norway, Canada, and Australia, [207] focuses on the UK and Wales, and finally [208] considers the UK market for arbitrage purposes.

In addition, quite some studies discuss a relaxation of the perfect price foresight assumption (e.g., [201, 209, 210, 211, 212, 213, 214]). References [201, 209] use a backcasting approach and analyze the PJM market. The method used in [210, 211] is based on average prices of a user-specified period around which a price at which is bought and at which is sold is defined, and is applied to 13 DA markets in [210] and to Denmark in [211]. In [212] a price forecast method is applied to Ontario, while [213] studies the NYISO market and forecasts the peak hours based on historical data. Finally, [214] includes a variety of random normally distributed forecast errors.

Although many works study a relaxation of the perfect foresight assumption, less attention has been given to the study of the price-effect in PBUC arbitrage models. However, either large-scale or multiple small-scale storage plants that are operated cooperatively could benefit from considering the price-effect of storage actions. Even when deciding on the storage actions as a price-taker, if its participation is assumed to not be included yet in the observed prices considering the price-effect in the ex-post calculation of the realized profit is relevant for additional large storage capacities, as it may reduce observed price spreads. First, [201, 215] introduce a method to account for this price-effect based on an observed linear relationship between the system load and price. Second, [32] introduces a constant so-called market resilience factor to represent the price-effect of (dis)charge actions. Third, [216] and [217] propose methodologies to relax the price-taking assumption by taking into account the residual inverse demand function. Although these methodologies provide insight in the arbitrage value and operation of large storage capacities, due to a lack of market data or a different research scope they are based on rather conceptual and simplified

[1] The second assumption is sometimes also referred to as the “exogenous price” vs. “price as a function of the considered player’s decisions” assumption [59].

price-effects and therefore result in (1) a suboptimal (dis)charge schedule and accompanying arbitrage value with respect to the actual price-effect, and (2) an ex-post gap between the expected and realized profit.

Therefore, this chapter focuses on considering the price-effect by including real-world market resilience data, which illustrates the impact on the DA price of a change in offer or demand volume for each hour, published by several European power exchanges.[2] This data represents the most detailed available price-effect data, as it is obtained by the power exchange running the market-clearing algorithm again for alternative scenarios, and thus takes into account (1) the hourly aggregated supply and demand curves, (2) interaction with neigboring markets through market-coupling, and (3) the presence of complex orders. This chapter focuses on the arbitrage value of additional storage capacity in the DA market, but does not aim to provide bidding strategies for storage plants (e.g., [218]). Instead, the storage operator is assumed to self-schedule his (dis)charge actions against a set of DA prices and market resilience functions that reflect how prices react to changes in quantity.

5.1.3 Contributions

The main contributions of this chapter with respect to previous research on electricity storage arbitrage is a comprehensive formulation of the electricity storage arbitrage problem including detailed operating constraints, and the presentation of a new methodology to account for the price-effect of (dis)charge actions. Since the latter is based on the implementation of real-world market resilience functions in the PBUC arbitrage model, it includes the most detailed available price-effect data. As such, this chapter presents a measure to (1) evaluate the performance of the price-taking assumption and price-making assumptions based on more conceptual and simplified price-effects, and to (2) provide an upper limit to the arbitrage value, given current market conditions, if both the hourly prices and price-effects are assumed to be known at the decision stage. The former is done for a storage operator that assumes to be a price-taker in the market by using the price-effect data to ex-post calculate the realized profit, as opposed to the expected profit based on prices that would occur in the absence of (dis)charge actions. In addition, as the piecewise linear nature of the market resilience data poses computational challenges, a stepwise approximation of the piecewise linear functions is proposed which reduces computational effort significantly while providing lower and upper bound approximations to the piecewise linear results. The analyses are executed for the Belgian DA market,

[2] In contrast to the considered market resilience data, the price elasticity of demand refers to the relative change in demand as a result from a relative change in the price, and is typically negative as the demand for most commodities decreases as the price increases [163].

and show that the price-effect has a strong impact on the operation and arbitrage value of large-scale storage.

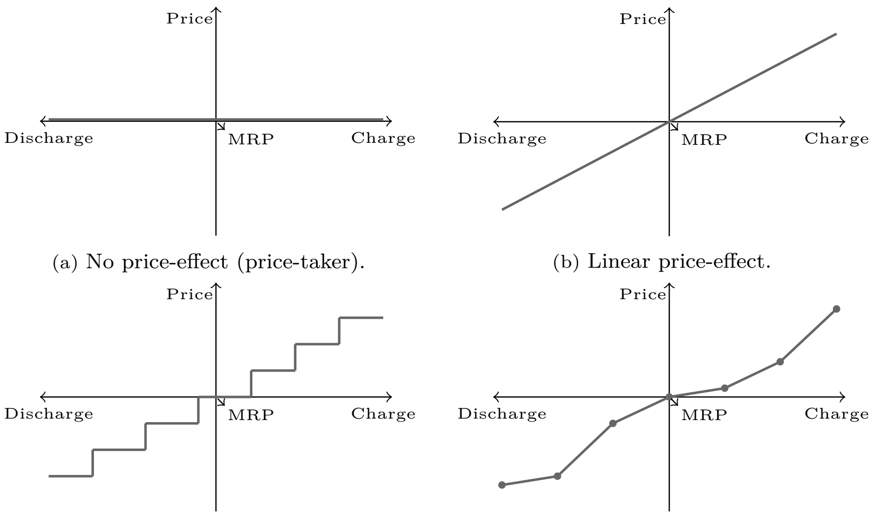
Section 5.2 discusses the price-effect in PBUC formulations of the arbitrage problem. Next, Section 5.3 provides a comprehensive formulation of the arbitrage problem with a price-taking assumption, while Section 5.4 extends this formulation by including the price-effect through piecewise linear and stepwise approximated market resilience functions. Section 5.5 discusses the results, and Section 5.6 provides conclusions.

5.2 The price-effect of storage actions

5.2.1 Literature review

Although a relaxation of the price-taking assumption (Fig. 5.2a) has been studied extensively in other frameworks (e.g., equilibrium models [219, 220, 221]), it has only been studied to a limited extent in PBUC electricity storage arbitrage models. First, references [201, 215] assume a monthly linear relationship between the price and system load for the DA market in the PJM region in the US, obtained by using ordinary least squares (OLS) regression. The slope associated with the OLS function is assumed to be non-decreasing and to capture the price-effect of (dis)charge actions (Fig. 5.2b). Second, [32] considers the Belgian DA market and defines a constant market resilience factor as price-effect for all (dis)charge volumes for the entire year (Fig. 5.2b). This factor is based on the DA market resilience data discussed in Section 5.1, but does not consider its time-varying and piecewise linear nature. Third, two approaches include the price-effect by considering residual inverse demand curves. In [216] the price-effect is studied for the Iberian DA market MIBEL, and is defined by a residual inverse demand curve that depends on the slopes of the demand and supply curves, and which is modeled through an approximated sigmoid function. Contrarily, [217] studies the price-effect in the context of the Greek DA market. The demand curve is assumed to be perfectly inelastic, while the mirrored image of the stepwise supply curve from other generation is assumed to represent the residual inverse demand curve. The resulting price is determined by the intersection of the stepwise supply curve and the vertical demand curve, with the latter's position depending on the storage plant's actions (Fig. 5.2c).

When considering generation capacity, a similar approach to [217] is applied in [222, 223] for a conventional hydro power plant. In addition, [224] discusses a methodology for generation companies to provide hourly offers by considering a series of possible residual inverse demand curves. These are selected from recent days similar to the considered day in terms of hourly demand, and are thus based on historical offers submitted by competing players.



(a) No price-effect (price-taker).

(b) Linear price-effect.

(c) Stepwise price-effect.

(d) Piecewise linear price-effect.

Figure 5.2: Overview of the price-taking vs. different price-making assumptions. The market reference point (MRP) refers to the situation without participation of the additional storage capacity, and is located at the origin.

Due to either a lack of available market data or the focus on a different research scope, the existing approaches include simplified representations of the price-effect. This may result in suboptimal (dis)charge schedules and resulting arbitrage value when evaluating against the actual price-effect, and incorrect estimates of the realized profit. When calculating the change in price, inaccuracies may originate from not considering (1) the time-varying aggregated supply and demand curves, (2) the acceptance of new block orders and rejection of currently cleared ones, and (3) changes in cross-border flows due to the coupling of geographically adjacent markets.

5.2.2 Hourly piecewise linear market resilience functions

The degree to which additional demand and supply would affect the Belgian DA price is captured by the market resilience data, published in the form of hourly piecewise linear functions (Fig. 5.2d) by the BELPEX power exchange [169].[3] As

[3]Such market resilience data is also published by the APX [170] and EPEX SPOT [171] power exchanges for other European countries.

stated before, this data is obtained by rerunning the market-clearing algorithm for six different scenarios (i.e., 50 MWh, 250 MWh, 500 MWh additional offer or demand volume at any price), and takes into account the aggregated supply and demand curves, interaction with neighboring markets through market-coupling, and presence of complex orders (e.g., block orders). Contrarily, only using the published aggregated offer curves from within a single market omits changes in cross-border flows due to market-coupling as well as the change in clearing of complex orders for the following reasons.

- The BELPEX DA market is coupled with other European power exchanges. The market-clearing algorithm combines the supply and demand bid information of the different exchanges to optimize the utilization of the available interconnection capacity. In case of a price difference between geographical markets, electric energy is exchanged until the price difference is eliminated or all available interconnection capacity is used. Consequently the effect of a local increase in offer or demand may not only affect the local market price but also the price in the coupled markets.[4] Since the price-effect in one market is a function of the market resilience of the local market as well as of the coupled markets, and the available interconnection capacity, merely considering the local power exchange's aggregated curves results in an overestimation of the total price-effect, including the impact of changed imports and exports.
- The standardized orders in DA markets are limit orders, i.e., hourly offered or requested quantities with a certain price limit. Besides these hourly orders, most exchanges also allow other, more complex, orders [225]. The most common one is a block order, which consists of quantities that are offered or requested in multiple hours at an average price limit and which has to be accepted completely or not at all. Due to their specific nature, such accepted sale and buy block orders are introduced in the aggregated supply and demand curve at the minimum and maximum price, respectively, thereby ignoring their price-sensitive character. If the price-effect would be simulated by simply shifting aggregated supply and demand curves, this would not capture the extent to which initially rejected block orders may be accepted and accepted block orders may now be rejected.

It is important to note that noniteratively solved PBUC formulations of the arbitrage problem assume that other players do not change their behavior with

[4]Since a demand increase in a market would result in an increased local price, this leads to an increased import (if interconnection capacity is available) which in turn increases the price in the exporting market and (partially) offsets the price increase in the local market. A similar reasoning holds for a supply increase.

participation of the additional storage capacity. PBUC models considering a price that is determined exogenously, i.e., independent of the considered storage plant's (dis)charge actions, assume a price-taking assumption and are useful to represent perfect competition conditions. In contrast, PBUC models in which a storage operator maximizes profit while considering its price-effect given the decisions of the competing players represent so-called leader-in-price models [59, 226]. In more complex games other players might react and change their behavior in response to entry of additional storage capacity.[5]

5.3 Day-ahead electricity storage arbitrage

The continuous time dimension, represented by time index t, is discretized, with h representing the discrete index, while the model formulations assume a fixed time step length T^{h} of one hour (Fig. 5.3). The storage operator uses electricity storage resources to maximize the arbitrage value on a daily basis over an optimization horizon of 48 hourly time steps ($\forall\, h \in \mathbb{H}$). In order to ensure that energy stored at the end of each 24 hour optimization period has so-called carryover value [201], each optimization is done with a 48 hour horizon to determine the dispatch of each 24 hour period. The storage operator is thus assumed to decide upon the charge power p_h^{c} and discharge power p_h^{d} based on short-term DA price differences throughout the day, and is assumed to have a perfect knowledge of these prices for the upcoming optimization period.[6]

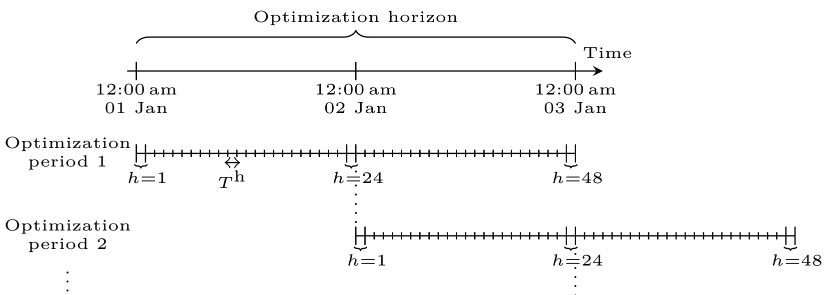


Figure 5.3: Time dimension discretization and rolling optimization horizon.

An electricity storage plant can typically be characterized by the minimum and maximum charge power rating $P^{\mathrm{c,min}}$ and $P^{\mathrm{c,max}}$, discharge power rating

[5]In such games, not only local competitors, but also those in neighboring market zones have to be considered due to market-coupling.

[6]The rolling optimization horizon restricts the perfect foresight to the next 48 hours.

$P^{\mathrm{d,min}}$ and $P^{\mathrm{d,max}}$, and energy storage capacity E^{min} and E^{max}, the charge and discharge efficiency η^{c} and η^{d}, and the down and upward ramp rate in charge mode $R^{\mathrm{c,do}}$ and $R^{\mathrm{c,up}}$ and in discharge mode $R^{\mathrm{d,do}}$ and $R^{\mathrm{d,up}}$. In addition, storage plants have a limited lifetime, which is either determined by the calendar life N^{cal} in case of infrequent use or by the cycle-life N^{cyc} in case of frequent use [92].[7] The calendar life is the maximum time that the storage plant can be used, independent from the use, while the cycle-life takes into account the deterioration of the energy storage subsystem due to use. The latter is particularly important when considering a BES system due to the partial nonreversibility of the chemical reactions. Although there is no direct constraint on the number of cycles during each optimization period, due to the limited cycle-life it is implied that the targeted cycling rate $N^{\mathrm{cyc}}/N^{\mathrm{cal}}$ is constant throughout the lifetime. If the cycling rate n^{cyc} (5.9) is lower than or equal to the targeted cycling rate, the depreciation cost resulting from cycling c^{cyc} is zero, otherwise $c^{\mathrm{cyc}} > 0$ (Fig. 5.4). This formulation to include the limited cycle-life and resulting depreciation cost is derived from [92]. Contrary to BES systems, for PHS plants the cycle-life is sufficiently large such that c^{cyc} is negligible. Furthermore, this chapter assumes changes in the buffered energy due to exogenous power flows to be negligible in the short-term.

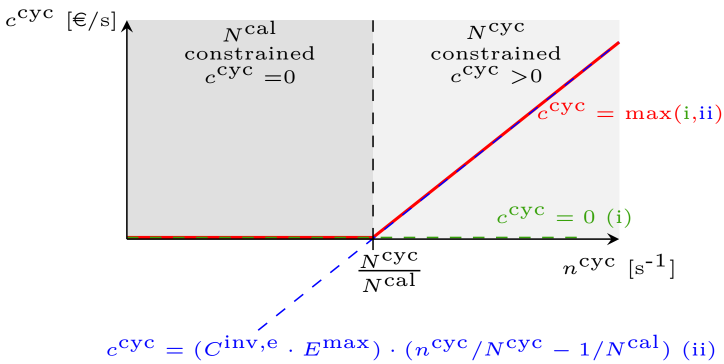


Figure 5.4: Opportunity cost for wearing out the energy storage subsystem.

Since the storage operator is assumed to be a price-taker in this initial problem formulation, the (dis)charge schedule is optimized not taking into account the (potential) impact on the price without its participation $\lambda_h^{\mathrm{da,o}}$. The resulting problem is an MILP which is solved in GAMS using the CPLEX solver [227]:

[7] The cycle-life is usually defined as the number of cycles before the remaining usable capacity falls below 80 % of the initial storage capacity due to wear.

$$\pi^{\mathrm{op}} = \max_{\substack{b_h, c^{\mathrm{cyc}}, e_h, \\ n^{\mathrm{cyc}}, p^{\mathrm{c}}_h, p^{\mathrm{d}}_h}} \sum_{h \in \mathbb{H}} \lambda^{\mathrm{da,o}}_h \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_h - p^{\mathrm{c}}_h)\right] / (|\mathbb{H}| \cdot T^{\mathrm{h}}) - c^{\mathrm{cyc}}, \tag{5.2}$$

$$\text{s.t.} \quad e_h = e_{h\text{-}1} + T^{\mathrm{h}} \cdot (p^{\mathrm{c}}_h \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_h / \eta^{\mathrm{d}}), \qquad \forall\, h \in \mathbb{H}, \tag{5.3}$$

$$-R^{\mathrm{c,do}} \cdot P^{\mathrm{c,max}} \leq (p^{\mathrm{c}}_h - p^{\mathrm{c}}_{h\text{-}1})/T^{\mathrm{h}} \leq R^{\mathrm{c,up}} \cdot P^{\mathrm{c,max}}, \qquad \forall\, h \in \mathbb{H}, \tag{5.4}$$

$$-R^{\mathrm{d,do}} \cdot P^{\mathrm{d,max}} \leq (p^{\mathrm{d}}_h - p^{\mathrm{d}}_{h\text{-}1})/T^{\mathrm{h}} \leq R^{\mathrm{d,up}} \cdot P^{\mathrm{d,max}}, \qquad \forall\, h \in \mathbb{H}, \tag{5.5}$$

$$0 \leq P^{\mathrm{c,min}} \cdot b_h \leq p^{\mathrm{c}}_h \leq P^{\mathrm{c,max}} \cdot b_h, \qquad \forall\, h \in \mathbb{H}, \tag{5.6}$$

$$0 \leq P^{\mathrm{d,min}} \cdot (1 - b_h) \leq p^{\mathrm{d}}_h \leq P^{\mathrm{d,max}} \cdot (1 - b_h), \qquad \forall\, h \in \mathbb{H}, \tag{5.7}$$

$$0 \leq E^{\mathrm{min}} \leq e_h \leq E^{\mathrm{max}}, \qquad \forall\, h \in \mathbb{H}, \tag{5.8}$$

$$n^{\mathrm{cyc}} = \eta^{\mathrm{c}} \cdot \sum_{h \in \mathbb{H}} p^{\mathrm{c}}_h / E^{\mathrm{max}}, \tag{5.9}$$

$$c^{\mathrm{cyc}} \geq (C^{\mathrm{inv,e}} \cdot E^{\mathrm{max}}) \cdot (n^{\mathrm{cyc}}/N^{\mathrm{cyc}} - 1/N^{\mathrm{cal}}), \tag{5.10}$$

$$c^{\mathrm{cyc}}, e_h, n^{\mathrm{cyc}}, p^{\mathrm{c}}_h, p^{\mathrm{d}}_h \in \mathbb{R}_+\,,\ b_h \in \{0,1\}\,,\ \mathbb{H} \subset \mathbb{N}, \qquad \forall\, h \in \mathbb{H}. \tag{5.11}$$

The objective value in (5.2) expresses the operating profit π^{op}, which does not consider the electricity storage plant's investment cost. Constraint (5.3) expresses the intertemporal character of electricity storage, while (5.4) and (5.5) limit the change in (dis)charge power by the storage plant's ramp rates. Constraints (5.6)-(5.8) represent capacity bounds on the (dis)charge power and storage capacity, with binary variable b_h ensuring that the storage plant is operated with a strict separation of the electricity consumption and generation phase, i.e., $p^{\mathrm{c}}_h \cdot p^{\mathrm{d}}_h = 0\ \forall\, h$. If however simultaneous charging and discharging is technically feasible (e.g., in certain PHS plants), it is profitable to ignore the nonsimultaneity constraint during negative price periods.[8] The nonnegativity of c^{cyc} and (5.9)-(5.10) represent the convex relaxation[9] of the max operator illustrated in Fig. 5.4, with $C^{\mathrm{inv,e}}$ the investment cost of the energy-component of the storage plant. The intertemporal equation (5.3) indicates that if the

[8]During negative price periods the storage operator is paid to consume electric energy, and will therefore attempt to fill the storage buffer as quickly as possible. When the upper limit of the storage buffer is reached during these periods, it is profitable to charge and discharge simultaneously, thereby being remunerated for the incurred energy losses.

[9]As c^{cyc} is minized in (5.2), the convex relaxation leads to a result satisfying the original max operator.

storage plant consumes p_h^{c} electric power during T^{h} then the stored energy level e_h increases by $T^{\mathrm{h}} \cdot p_h^{\mathrm{c}} \cdot \eta^{\mathrm{c}}$, while if the storage plant generates p_h^{d} electric power during T^{h} then the stored energy level e_h decreases by $T^{\mathrm{h}} \cdot p_h^{\mathrm{d}}/\eta^{\mathrm{d}}$. When $h = 1$ in (5.3)-(5.5), index h-1 indicates $h = 24$ of the previous daily optimization period, except for the first optimization period where index h-1 at $h = 1$ refers to starting values for the (dis)charge power and stored energy.

Given the (dis)charge schedule decided upon by the storage operator that does not consider the potential price-effect, the resulting DA prices can be calculated ex-post for price-taking storage participations that are assumed not to be included yet in the given DA prices. This is done by interpolating the piecewise linear market resilience functions. These prices are used to calculate the realized π^{op}, as opposed to the expected π^{op} following $\lambda_h^{\mathrm{da,o}}$, of additional storage resources.[10]

5.4 Relaxing the price-taking assumption

5.4.1 Including time-varying piecewise-linear market resilience functions

Detailed price resilience data is provided by several European power exchanges in the form of time-varying piecewise linear functions (Fig. 5.5), which may be nonconvex and include both increasing and counterintuitive decreasing linear segments. Segments are considered to be intuitive if the price decreases with additional supply and increases with additional demand, while counterintuitive segments are the result of differences in accepted block orders: additional supply can cause supply (demand) block orders that are accepted (rejected) in the reference case to become rejected (accepted), while additional demand can cause demand (supply) block orders that are accepted (rejected) in the reference case to become rejected (accepted). For the Belgian DA market in 2014, 70.5 % of the segments include intuitive slopes, 19.5 % include counterintuitive slopes, and 10 % of the segments are horizontal, i.e., no change in price due to a change in quantity.

[10] The expected π^{op} is identical to the realized π^{op} in the situation in which the storage plant is assumed to be small enough to not affect observed prices, or in which these prices are assumed to already include its price-taking participation. The expected and realized π^{op} may differ in the situation in which the storage actions may affect the observed prices, with this effect assumed to not be included yet, and the operator not recognizing this price-effect. In the remainder of this chapter, the expected π^{op} corresponds to (1) the expected and realized values in the first type of situation, and (2) the expected value in the second type of situation. In contrast, the realized π^{op} corresponds to the realized value in the second type of situation.

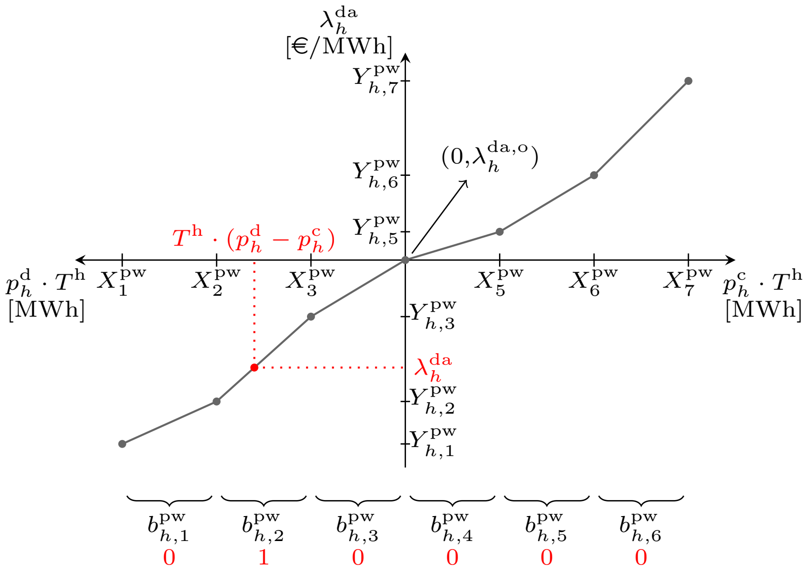


Figure 5.5: Illustration of piecewise linear market resilience functions.

To include these piecewise linear functions in the arbitrage problem formulation, a set $k \in \mathbb{K}$ of piecewise linear function breakpoints and a variable $\delta_{h,k}$, which can be considered as a special ordered set of type two (SOS2) variable [228], are introduced. For the Belgian DA market, the piecewise linear functions have seven fixed breakpoints (i.e., $|\mathbb{K}| = 7$) along the x-axis (i.e., (dis)charge volumes) indicated by X_k^{pw}, while the corresponding time-dependent y-axis values (i.e., prices) are indicated by $Y_{h,k}^{\mathrm{pw}}$. The MRP lies at breakpoint $k = 4$, with $X_4^{\mathrm{pw}} = 0$ and $Y_{h,4}^{\mathrm{pw}} = \lambda_h^{\mathrm{da,o}}$. For each breakpoint k there is a nonnegative $\delta_{h,k}$, which is bounded by 1 and which may be larger than 0 for at most two breakpoints. If there are two positive $\delta_{h,k}$, they must correspond to adjacent breakpoints and take on values between 0 and 1, depending the weighted share of the corresponding breakpoints' x-axis values and y-axis values in the calculation of the chosen (dis)charge volume and resulting DA price:

$$\delta_{h,k} = \frac{|X_{k+1}^{\mathrm{pw}} - T^{\mathrm{h}} \cdot (p_h^{\mathrm{d}} - p_h^{\mathrm{c}})|}{|X_k^{\mathrm{pw}} - X_{k+1}^{\mathrm{pw}}|} = \frac{|Y_{h,k+1}^{\mathrm{pw}} - \lambda_h^{\mathrm{da}}|}{|Y_{h,k}^{\mathrm{pw}} - Y_{h,k+1}^{\mathrm{pw}}|}, \tag{5.12}$$

$$\delta_{h,k+1} = \frac{|X_k^{\mathrm{pw}} - T^{\mathrm{h}} \cdot (p_h^{\mathrm{d}} - p_h^{\mathrm{c}})|}{|X_k^{\mathrm{pw}} - X_{k+1}^{\mathrm{pw}}|} = \frac{|Y_{h,k}^{\mathrm{pw}} - \lambda_h^{\mathrm{da}}|}{|Y_{h,k}^{\mathrm{pw}} - Y_{h,k+1}^{\mathrm{pw}}|}. \tag{5.13}$$

Alternatively, one $\delta_{h,k}$ might take on the value 1, which means that the storage operator decides to be at one of the breakpoints. The adjacency condition is enforced by incorporating additional binary variables $b^{\mathrm{pw}}_{h,k}$, corresponding to the segments between adjacent breakpoints.

The DA arbitrage objective function is now (5.14), which is still subject to (5.3)-(5.10), and is now additionally subject to (5.15)-(5.19). The resulting problem is a nonconvex MIQP which is solved in GAMS using the SBB solver [229]:

$$\pi^{\mathrm{op}} = \max_{\substack{b_h, b^{\mathrm{pw}}_{h,k}, c^{\mathrm{cyc}}, \\ e_h, n^{\mathrm{cyc}}, p^{\mathrm{c}}_h, \\ p^{\mathrm{d}}_h, \lambda^{\mathrm{da}}_h, \delta_{h,k}}} \sum_{h \in \mathbb{H}} \lambda^{\mathrm{da}}_h \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_h - p^{\mathrm{c}}_h)\right] / (|\mathbb{H}| \cdot T^{\mathrm{h}}) - c^{\mathrm{cyc}}, \tag{5.14}$$

$$\text{s.t.} \quad (5.3)\text{-}(5.11),$$

$$T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_h - p^{\mathrm{c}}_h) = \sum_{k \in \mathbb{K}} \delta_{h,k} \cdot X^{\mathrm{pw}}_k, \qquad \forall\, h \in \mathbb{H}, \tag{5.15}$$

$$\lambda^{\mathrm{da}}_h = \sum_{k \in \mathbb{K}} \delta_{h,k} \cdot Y^{\mathrm{pw}}_{h,k}, \qquad \forall\, h \in \mathbb{H}, \tag{5.16}$$

$$\sum_{k \in \mathbb{K}} \delta_{h,k} = 1, \qquad \forall\, h \in \mathbb{H}, \tag{5.17}$$

$$\sum_{k \in \mathbb{K} \setminus \{|\mathbb{K}|\}} b^{\mathrm{pw}}_{h,k} = 1, \qquad \forall\, h \in \mathbb{H}, \tag{5.18}$$

$$\begin{aligned} &\delta_{h,k} \le b^{\mathrm{pw}}_{h,k}, && \forall\, h \in \mathbb{H}, k = 1, \\ &\delta_{h,k} \le b^{\mathrm{pw}}_{h,k\text{-}1} + b^{\mathrm{pw}}_{h,k}, && \forall\, h \in \mathbb{H}, k \in \mathbb{K} \setminus \{1, |\mathbb{K}|\}, \\ &\delta_{h,k} \le b^{\mathrm{pw}}_{h,k\text{-}1}, && \forall\, h \in \mathbb{H}, k = |\mathbb{K}|, \end{aligned} \tag{5.19}$$

$$\delta_{h,k} \in \mathbb{R}_+ \,,\ \lambda^{\mathrm{da}}_h \in \mathbb{R} \,,\ b^{\mathrm{pw}}_{h,k} \in \{0,1\} \,,\ \mathbb{K} \subset \mathbb{N}, \quad \forall\, h \in \mathbb{H}, k \in \mathbb{K}. \tag{5.20}$$

Since solving this nonconvex MIQP requires significant computation time, a stepwise approximation of the piecewise linear functions is discussed in Section 5.4.2. This approximation converts the problem into an easier to solve MILP, and furthermore allows to determine lower and upper bound approximations to the piecewise linear outcome.

5.4.2 Stepwise approximation of time-varying piecewise linear functions

This method approximates each linear segment of the piecewise linear market resilience functions by a stepwise function with identical step heights. A target step height S^{tar} is set for all linear segments, but is updated to $S^{\text{upd}}_{h,k}$ in (5.23) by (5.22) for each time slot and linear segment individually if the divison's remainder $0 \leq R^{\text{div}}_{h,k} \leq 1$ in (5.21) is larger than zero:

$$\frac{|Y^{\text{pw}}_{h,k} - Y^{\text{pw}}_{h,k+1}|}{S^{\text{tar}}} = N^{\text{sw}}_{h,k} + R^{\text{div}}_{h,k}, \quad \forall\, h \in \mathbb{H}, k \in \mathbb{K}\backslash\{|\mathbb{K}|\}, \tag{5.21}$$

$$N^{\text{sw}}_{h,k} = N^{\text{sw}}_{h,k} + 1 \quad \text{if} \quad R^{\text{div}}_{h,k} > 0, \quad \forall\, h \in \mathbb{H}, k \in \mathbb{K}\backslash\{|\mathbb{K}|\}, \tag{5.22}$$

$$S^{\text{upd}}_{h,k} = \frac{|Y^{\text{pw}}_{h,k} - Y^{\text{pw}}_{h,k+1}|}{N^{\text{sw}}_{h,k}}, \qquad \forall\, h \in \mathbb{H}, k \in \mathbb{K}\backslash\{|\mathbb{K}|\}, \tag{5.23}$$

with $N^{\text{sw}}_{h,k} \in \mathbb{N}_0$ the number of steps to approximate the linear segment between breakpoints k and $k{+}1$. The resulting time-varying stepwise function's total number of steps $\sum_{k\in\mathbb{K}\backslash\{|\mathbb{K}|\}} N^{\text{sw}}_{h,k}$, determined by S^{tar}, relates to the preferred trade-off between computation time and approximation error.[11]

For each time slot, three stepwise functions are constructed. Two of them allow to calculate a lower and upper bound to π^{op} following the piecewise linear market resilience functions. The lower bound is calculated by considering a larger price-effect compared to the piecewise linear price-effect, thereby underestimating π^{op}, while the upper bound is calculated by considering a smaller price-effect, thereby overestimating π^{op}. The former is based on a stepwise function that approximates the piecewise linear function such that λ^{da}_h is identical or less favorable for all (dis)charge actions, while the latter's stepwise function approximates the piecewise linear function such that λ^{da}_h is identical or more favorable (Fig. 5.6).[12] Although this method provides lower and upper bounds when considering a single optimization period, this might not be true for each individual optimization in a rolling horizon framework if the starting value for the stored energy level, carried over from the previous optimization period, differs. Therefore, they should be interpreted as lower and upper bound approximations rather than true bounds when consecutively considering multiple optimization problems. The third stepwise function is

[11] Alternatively, an iterative approach could be applied in which first a rather large step size is used, after which it is successively refined in the neighborhood of the most recent solution.

[12] Less favorable indicates higher prices when charging and lower prices when discharging, while more favorable indicates lower prices when charging and higher prices when discharging.

centered along the piecewise linear function (Fig. 5.6), but does not provide information on whether the obtained result is an over or underestimation.

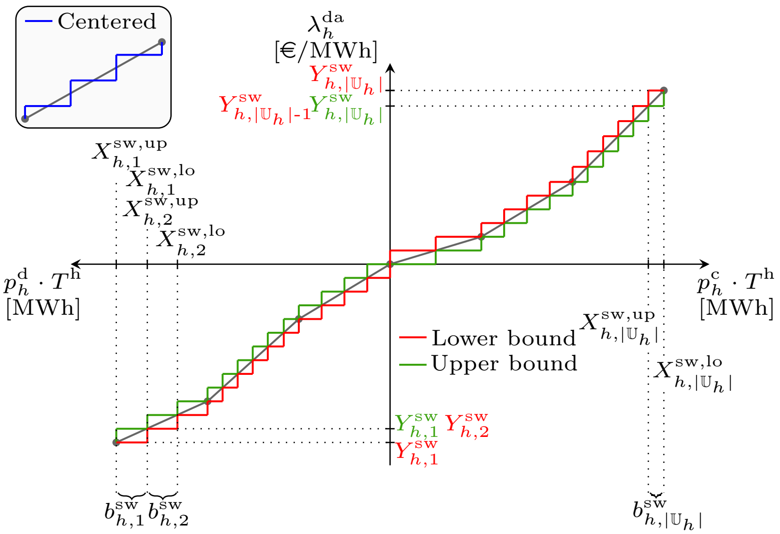


Figure 5.6: Lower bound, upper bound, and centered stepwise approximation of the piecewise linear market resilience functions.

The objective function is (5.24), with $u \in \mathbb{U}_h$ the set of steps of the stepwise market resilience function, and $p^{\mathrm{c}}_{h,u}$, $p^{\mathrm{d}}_{h,u}$, $Y^{\mathrm{sw}}_{h,u}$ the charge power, discharge power, and DA price that correspond to step u, respectively. The objective function is still subject to (5.3)-(5.10), and now additionally subject to (5.25)-(5.29), with $X^{\mathrm{sw,lo}}_{h,u}$ and $X^{\mathrm{sw,up}}_{h,u}$ being the lower and upper bound of the (dis)charge volume corresponding to step u, respectively. The binary variables $b^{\mathrm{sw}}_{h,u}$ correspond to the steps of the stepwise function, and can be considered as special ordered set of type one (SOS1) variables [228]. The resulting problem is formulated as an MILP which is solved in GAMS using the CPLEX solver:

$$\pi^{\mathrm{op}} = \max_{\substack{b_h, b^{\mathrm{sw}}_{h,u}, c^{\mathrm{cyc}}, \\ e_h, n^{\mathrm{cyc}}, p^{\mathrm{c}}_h, \\ p^{\mathrm{c}}_{h,u}, p^{\mathrm{d}}_h, p^{\mathrm{d}}_{h,u}}} \sum_{h \in \mathbb{H}} \sum_{u \in \mathbb{U}_h} \left[Y^{\mathrm{sw}}_{h,u} \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_{h,u} - p^{\mathrm{c}}_{h,u}) \right] \right] / (|\mathbb{H}| \cdot T^{\mathrm{h}}) - c^{\mathrm{cyc}}, \quad (5.24)$$

s.t. (5.3)-(5.11), (5.20),

$$\sum_{u \in \mathbb{U}_h} p^{\mathrm{c}}_{h,u} = p^{\mathrm{c}}_h, \qquad \forall\, h \in \mathbb{H}, \qquad (5.25)$$

$$\sum_{u \in \mathbb{U}_h} p^{\mathrm{d}}_{h,u} = p^{\mathrm{d}}_{h}, \qquad \forall\, h \in \mathbb{H}, \tag{5.26}$$

$$b^{\mathrm{sw}}_{h,u} \cdot X^{\mathrm{sw,lo}}_{h,u} \leq T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_{h,u} - p^{\mathrm{c}}_{h,u}) \leq b^{\mathrm{sw}}_{h,u} \cdot X^{\mathrm{sw,up}}_{h,u}, \quad \forall\, h \in \mathbb{H}, u \in \mathbb{U}_h, \tag{5.27}$$

$$\sum_{u \in \mathbb{U}_h} b^{\mathrm{sw}}_{h,u} = 1, \qquad \forall\, h \in \mathbb{H}, \tag{5.28}$$

$$p^{\mathrm{c}}_{h,u}, p^{\mathrm{d}}_{h,u} \in \mathbb{R}_+\,,\; b^{\mathrm{sw}}_{h,u} \in \{0,1\}\,, \qquad \forall\, h \in \mathbb{H}, u \in \mathbb{U}_h, \tag{5.29}$$

$$\mathbb{U}_h = \{1, 2, ..., \sum_{k \in \mathbb{K} \setminus \{|\mathbb{K}|\}} N^{\mathrm{sw}}_{h,k}\}, \qquad \forall\, h \in \mathbb{H}. \tag{5.30}$$

5.5 Results

Unless specified otherwise, the used storage plant characteristics, along with other input data, are displayed in Table 5.1, and serve to model typical PHS plants. In addition, Fig. 5.7 provides information on the average market resilience curve slope up to 500 MWh additional supply and 500 MWh additional demand.

Table 5.1: Input parameters.

$C^{\mathrm{inv,e}}$	50	€/MWh	N^{cyc}	100 000	-	$P^{\mathrm{d,min}}$	0	MW	$R^{\mathrm{d,up}}$	50	%/min
E^{max}	2000	MWh	$P^{\mathrm{c,max}}$	500	MW	$R^{\mathrm{c,do}}$	50	%/min	η^{c}	86.6	%
E^{min}	0	MWh	$P^{\mathrm{c,min}}$	0	MW	$R^{\mathrm{c,up}}$	50	%/min	η^{d}	86.6	%
N^{cal}	50	a	$P^{\mathrm{d,max}}$	500	MW	$R^{\mathrm{d,do}}$	50	%/min			
$\lvert\mathbb{H}\rvert$	48	-	$\lvert\mathbb{K}\rvert$	7	-	S^{tar}	1.0	€/MWh	T^{h}	1	h

5.5.1 Computational performance and accuracy of the stepwise approximation

Table 5.2 validates the use of the stepwise approximations for the piecewise linear market resilience functions, in order to move from a nonconvex MIQP to an MILP. Both the operating profit π^{op} and computation time[13] following the stepwise approximation are expressed in relative terms compared to the piecewise linear values (i.e., the values for the MIQP represent 100 %). This

[13]The computation time is defined as the time used by the solver, given by the GAMS parameter “resusd”, while all models are solved to optimality by setting the GAMS option “optcr” to zero.

is done for twelve separate optimization periods of 12 time steps each, as for longer periods (e.g., 24 time steps) multiple hours of computation time did not suffice to solve the nonconvex MIQP to optimality.

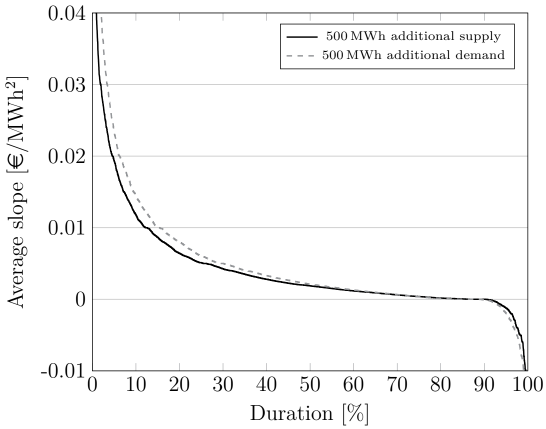


Figure 5.7: Average market resilience curve slope [€/MWh^2] up to 500 MWh additional demand (upward slope from the MRP) and up to 500 MWh additional supply (downward slope from the MRP), Belgium, 2014. Positive values indicate intuitive price-effects, while negative values indicate counterintuitive price-effects.

Table 5.2 shows that π^{op} following the stepwise approximation effectively provides tight lower and upper bounds to π^{op} following the piecewise linear functions, while only requiring a fraction of the computation time. In addition, these bounds become more accurate as S^{tar} is set to a smaller value while only incurring a slight increase in computation time, with the $S^{\mathrm{tar}} = 0.1$ €/MWh bounds to π^{op} located in between the $S^{\mathrm{tar}} = 1.0$ €/MWh bounds. Although the centered stepwise approximation provides accurate estimations of π^{op} as well, these might be both under or overestimations.

5.5.2 Operating profit as a function of storage size

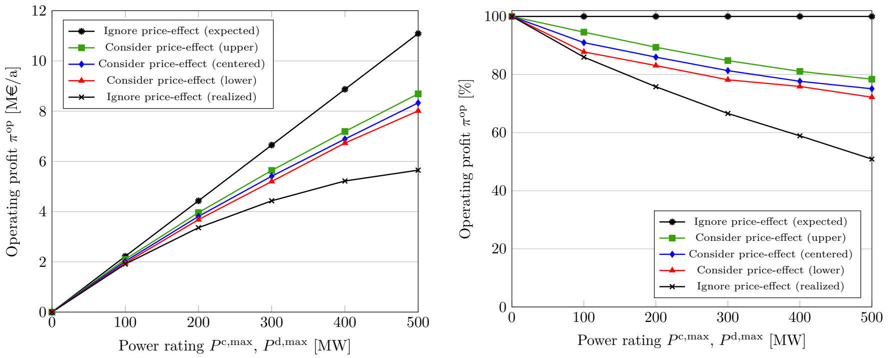
Fig. 5.8 shows π^{op} for 2014 for increasing storage power rating sizes assuming a fixed discharge E2P ratio $E^{\mathrm{max}}/P^{\mathrm{d,max}}$ of 4 h. Fig. 5.8a displays π^{op} in absolute values, while Fig. 5.8b illustrates π^{op} relative to the expected operating profit when assuming to be a price-taker in the market. When the storage operator assumes to be a price-taker and thus not considers the price-effect when deciding on the (dis)charge schedule, the expected π^{op} increases linearly with the storage size, as price spreads remain constant. However, when ex-post calculating the resulting DA price using the market resilience data, the realized π^{op} given the (dis)charge schedule decided upon by the price-taking storage operator is lower, with the gap between expected and realized π^{op} being negligible for small storage plants but increasing with the size of additional storage resources. Contrarily, in order to retrieve the upper limit to π^{op} of additional storage capacity, the price-effect is already considered at the decision stage. The results show both a lower and upper bound approximation to π^{op} following the piecewise linear price-effect, as well as an approximation based on a centered stepwise function. As more additional capacity is used for arbitrage, the incremental π^{op} decreases due to the price-effect, resulting in a trade-off between the capacity used and the average profit per unit.

Table 5.2: Validation of the stepwise approximation's lower and upper bound to π^{op} following piecewise linear price-effects, as well as of the centered stepwise approximation, Belgium, 2014. The MILP values are shown relative to the MIQP values, which represent 100 %.

Optimization period		$S^{\mathrm{tar}} = 0.1$ €/MWh						$S^{\mathrm{tar}} = 1.0$ €/MWh					
		Lower bound		Upper bound		Centered		Lower bound		Upper bound		Centered	
Hour	Date	π^{op} [%]	Time [%]	π^{op} [%]	Time [%]	π^{op} [%]	Time [%]	π^{op} [%]	Time [%]	π^{op} [%]	Time [%]	π^{op} [%]	Time [%]
1 - 12	Jan 1	99.92	1.69	100.60	1.82	100.26	1.67	99.92	0.15	102.46	0.17	101.18	0.19
1 - 12	Feb 1	99.98	0.03	100.13	0.03	100.06	0.03	99.96	0.01	101.16	0.01	100.56	0.01
1 - 12	Mar 1	99.92	0.27	100.05	0.26	99.97	0.24	99.67	0.02	100.46	0.03	100.04	0.02
1 - 12	Apr 1	99.95	18.43	101.16	17.75	100.55	19.78	99.89	1.80	105.91	1.57	102.89	1.80
1 - 12	May 1	99.93	0.38	100.16	0.43	100.04	0.42	99.72	0.04	100.90	0.03	100.31	0.04
1 - 12	Jun 1	99.90	0.76	100.06	0.89	99.98	0.85	99.16	0.05	100.16	0.05	99.66	0.05
1 - 12	Jul 1	99.94	0.39	100.15	0.42	100.05	0.40	98.78	0.01	100.55	0.02	99.67	0.01
1 - 12	Aug 1	99.99	0.91	100.53	1.00	100.26	0.99	99.67	0.08	103.71	0.10	101.49	0.12
1 - 12	Sep 1	99.97	5.61	100.33	6.51	100.15	6.58	98.84	0.49	101.92	0.49	100.30	0.69
1 - 12	Oct 1	100.00	0.05	100.36	0.04	100.18	0.05	99.93	0.01	102.68	0.01	101.27	0.01
1 - 12	Nov 1	99.86	0.61	100.15	0.58	100.01	0.62	98.78	0.07	100.92	0.05	99.85	0.05
1 - 12	Dec 1	99.70	0.18	100.20	0.18	99.95	0.29	98.34	0.01	101.27	0.01	99.66	0.01

5.5.3 (Dis)charge schedule and price profile

A duration curve of the (dis)charge actions for 2014 is displayed in Fig. 5.9, for both a storage operator which is assumed to be a price-taker in the market and a storage operator that takes into account its price-effect. In the former case the (dis)charge power rating is always used to its full capacity when (dis)charging, unless bounded by the limited energy storage capacity. Contrarily, in the latter case fewer full load hours (19 % vs. 31.6 %) are observed when taking into account the price-effect of (dis)charge actions to keep price spreads from diminishing too much. Although (dis)charge actions are partially shifted to neighboring hours, observed through the increased number of operational hours of the storage plant (47.3 % vs. 39.6 %), in total less energy is charged (733.2 GWh vs. 893.3 GWh) and discharged (549.9 GWh vs. 670 GWh). When considering the price-effect the total energy that is charged and discharged is shown by the colored area between the red line and the x-axis (Fig. 5.9); when ignoring the price-effect a similar reasoning holds with respect to the black line.



(a) Absolute values.

(b) Relative values.

Figure 5.8: Expected and realized π^{op} when not considering the price-effect, and a lower and upper bound, as well as a centered, stepwise approximation to π^{op} when considering the piecewise linear price-effect, Belgium, 2014.

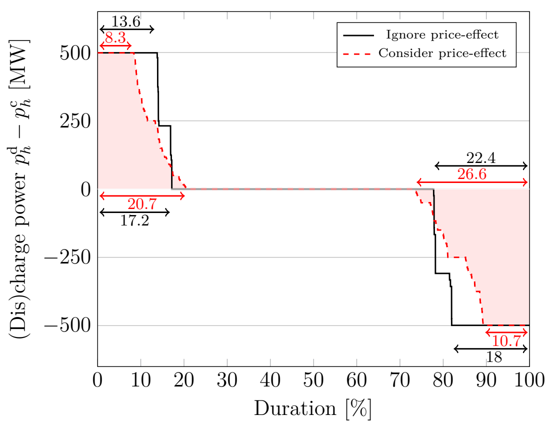
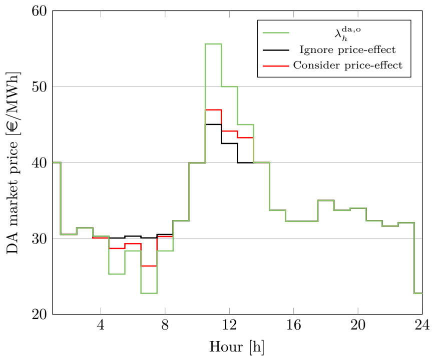
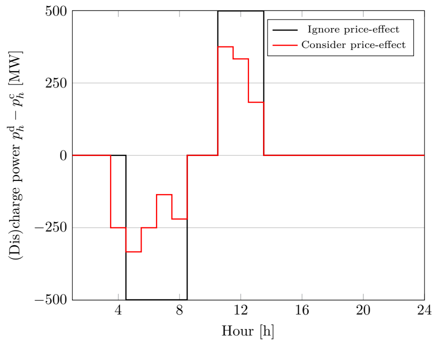


Figure 5.9: Considering the price-effect leads to fewer full load hours, more operational hours, and less (dis)charged energy in total, Belgium, 2014. The illustrated (dis)charge actions when considering the price-effect are those of the lower bound approximation.

Fig. 5.10 shows an example of a daily price profile and (dis)charge schedule. It shows that when not considering the price-effect the storage operator (dis)charges at full power rating, while when considering the price-effect a trade-off occurs between used capacity and remaining price-spread. The charge action is partly shifted to market period 4, which is not just characterized by a smaller price-effect compared to market periods 5 to 8, but by a counterintuitive one as the price decreases when charging. The resilience function for market period 4 shows a slightly decreasing slope up to 250 MWh additional demand, after which the slope increases, hence a charge action of 250 MW during hour 4.



(a) Price profile.



(b) (Dis)charge schedule.

Figure 5.10: The price profile and (dis)charge schedule. When not considering the price-effect the storage operator (dis)charges at full power rating, while when considering the price-effect a trade-off emerges between used (dis)charge power and remaining price-spread, Belgium, May 10, 2014. The illustrated price profile and (dis)charge schedule when considering the price-effect are those of the lower bound approximation.

5.5.4 Discussion: yearly arbitrage value compared to annualized investment cost

To provide some perspective on the order of magnitude of the obtained DA arbitrage value for Belgium for 2014, it is compared to the annualized investment cost of the considered PHS plant. As the available literature provides a wide range of investment cost estimations (e.g., [39]), Table 5.3 shows a sensitivity analysis with regard to a variety of credible power-related and energy-related investment cost and weighted average cost of capital (WACC) estimations. It shows that for a storage plant with the characteristics displayed in Table 5.1, when using Belgian market data from 2014, DA market arbitrage does not provide adequate revenues to compensate for the annualized investment cost of PHS capacity in any of the analyzed investment cost and WACC scenarios. In addition, as more power is used for arbitrage, the remaining price-spread decreases due to the price-effect. Therefore, a trade-off occurs between the capacity used and the average profit per unit of power.

Similar to previous studies on the electricity storage economics (e.g., [15, 192]), it is concluded that maximizing the value of electricity storage likely requires the aggregation of multiple applications while accounting for the interdependence between potential revenue streams. Although some studies focus on the co-optimization of different storage applications (e.g., [33, 192, 230]), most articles focus on only a single application or allocate the storage power rating and energy capacity a priori when considering multiple applications. While applications can be aggregated by both a single market participant or by multiple players through the co-operation and sharing of storage resources, the latter has only been studied to a limited extent [32, 231].

Table 5.3: The share of the annualized investment cost that is covered by the DA market arbitrage operating profit for Belgium for 2014. A sensitivity analysis is provided for three different power-related and energy-related investment cost scenarios, and for three different WACC scenarios (i.e., 3 %, 5 %, 7 %).

	600 €/kW, 20 €/kWh			750 €/kW, 50 €/kWh			900 €/kW, 80 €/kWh		
	3 % [%]	5 % [%]	7 % [%]	3 % [%]	5 % [%]	7 % [%]	3 % [%]	5 % [%]	7 % [%]
Ignore price-effect (expected)	83.7	59.5	45.2	60.4	42.7	32.3	46.8	33.2	25.1
Consider price-effect (upper)	65.6	46.6	35.4	47.4	33.5	25.3	36.7	26.0	19.7
Consider price-effect (centered)	62.9	44.7	33.9	45.4	32.1	24.3	35.1	24.9	18.8
Consider price-effect (lower)	60.5	42.9	32.6	43.7	30.9	23.3	33.8	23.9	18.1
Ignore price-effect (realized)	42.6	30.3	23.0	30.8	21.8	16.4	23.8	16.9	12.8

5.6 Conclusions

Although the value of electricity storage arbitrage is directly related to the frequency and size of price spreads, it is also a function of the price-effect of (dis)charge actions. The price-effect represents the degree to which additional demand increases off-peak prices and additional supply decreases on-peak prices, and is, ceteris paribus, inversely correlated to the arbitrage value. While the impact of the price-effect is negligible for small storage volumes, it reduces the arbitrage value significantly for large storage volumes. In this chapter the price-effect is taken into account by considering real-world market resilience data, available in the form of hourly piecewise linear functions, and published by multiple European power exchanges. A nonconvex MIQP model is formulated and a stepwise approximated MILP model (for which the accuracy can be chosen) is derived to improve the computational tractability. This approach widens the scope with respect to previous works that model the price-effect as stepwise from the start.

Since this resilience data is only available ex-post, their application mainly lies in estimating the upper limit to the arbitrage value of additional storage capacity in a certain market given current market conditions, and the evaluation of the performance of the price-taking assumption and price-making assumptions based on more conceptual and simplified price-effects. The former assumes that the price-effect is already taken into account at the (dis)charge decision stage, while the latter can be done by ex-post calculating the realized profit as opposed to the anticipated profit.

Chapter 6

Multi-application operation

Quantifying the electricity storage arbitrage potential in short-term electricity markets in the CWE region

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Submitted for publication in Applied Energy:

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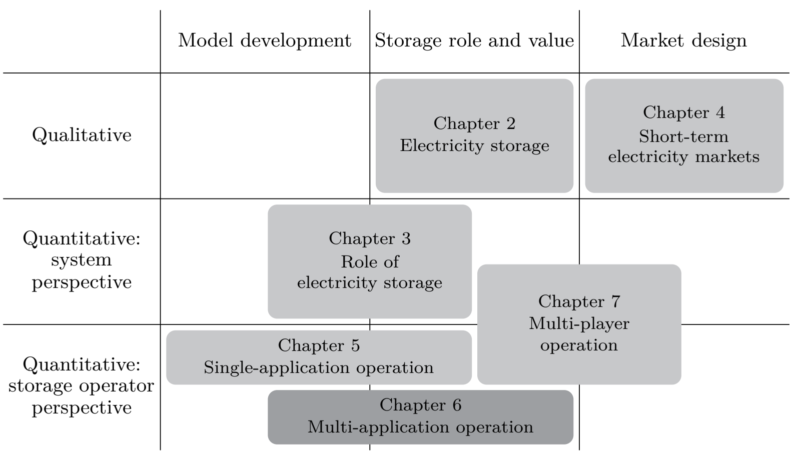
The first author is the main author of this article. The contributions of the first author include the literature study, the development of the models, the software implementation, the analysis and interpretation of the results, and the writing of the manuscript. The work is done with support and supervision from the second, third, and fourth author.

Abstract:

In electricity storage valuation studies, the lack of the (efficient) aggregation of applications in a single operation strategy is usually identified as a major barrier. Determining the true value of storage requires the aggregation of applications while accounting for the interdependence between revenue streams. Individual applications cannot simply be added together, but need to be co-optimized since they can interfere with each other. This chapter's contributions are threefold. First, we provide model formulations to aggregate multiple arbitrage opportunities, and to quantify the accompanying potential arbitrage

value. Whereas the storage arbitrage literature focuses on the capturing of price differences over time for the day-ahead market, we consider all three short-term markets, i.e., the day-ahead, intra-day, and real-time markets, and we consider the opportunity to capture three types of price differences: (1) over time in each individual market, (2) over the three markets for the same time step, and (3) over time over the three markets. Second, an important assumption in arbitrage models is related to whether storage operators recognize that their actions may affect those prices. This price-effect of storage actions has been considered before for the day-ahead market, but not for the intra-day and real-time markets. We study the price-effect with high detail for all three short-term markets, based on real-world price and volume data. Third, we apply the developed models to the four market zones of the Central Western European region, i.e., the Belgian, French, German, and Dutch market zones. As such, this chapter provides insight in the extent to which the three short-term markets, and their combination, in these market zones are potentially interesting for storage arbitrage. This assists improved decision-making of market participants in storage investment and operation, and informs policy-makers about the impact of market design on the potential storage value.

Positioning:



6.1 Introduction

6.1.1 Motivation

In Europe, market players self-schedule their assets based on trading in a series of consecutive markets. This trading can start up to a few years before delivery in the long-term forward and future markets, which usually continue until one day before physical generation and consumption. Next, trading continues in the DA and ID market, after which the TSO takes over to keep the system balanced by organizing the RT balancing market. The DA, ID, and RT market are generally referred to as the short-term electricity markets. Short-term markets are important tools to deal with the expected and unexpected variability in the system; variability materialises in these markets, thereby expressing the need for flexibility and offering a valorization platform. With the increasing variability in the system, resulting from the further integration of variable RES, the demand for flexibility increases and these markets become increasingly important [6].

A significant part of the growing attention for flexibility focuses on electricity storage, as one of the flexibility sources alongside flexible consumption and flexible generation, and the access to these sources in neighboring regions through the grid. Storage systems can be employed for different applications, which can generally be categorized in three groups: energy services include arbitrage and portfolio management; grid services include the provision of frequency control, congestion management, voltage support, and black-start capabilities to the system operator; reliability services include the support of reliability on the local level through back-up, uninterruptible power supply, and power quality management, and on the system level by contributing to generation adequacy. Even though there is an increasing demand for flexibility and multiple markets and applications exist for storage to participate in, recent studies point to difficult business cases. The lack of the (efficient) aggregation of applications in a single operating strategy is identified as a major barrier [13, 16, 32, 192]. This may be due to the presence of historical operation patterns, the complexity of revenue stacking, and the accompanying risk. In this chapter, we aim to further inform the discussion on the value of storage by stacking revenue streams from different arbitrage opportunities, resulting from the participation in all three short-term markets, in a single operating strategy.

6.1.2 Literature review

Arbitrage

Electricity storage arbitrage has been studied extensively, but almost exclusively in the context of capturing price differences over time in the DA market. The considered approaches range from a system perspective (e.g., [195, 196, 197, 198, 199, 200]) to an individual storage operator's perspective. The latter is the method adopted here, and is typically referred to as the PBUC formulation of the arbitrage problem. Generally, there are two important assumptions in PBUC formulations: the first is the perfect vs. imperfect price foresight assumption, which defines the operator's assumed knowledge of future prices, while the second is the price-taking vs. price-making assumption, defining whether the operator recognizes that its actions may have an impact on those prices [9, 201]. The second assumption corresponds to an exogenous price approach vs. price as a function of the player's decisions approach [59].

A large share of the PBUC storage arbitrage literature assumes perfect foresight of future prices and the storage plant to be small enough compared to the size of the market to not affect the prices (e.g., [204, 205, 206, 207, 208]). Furthermore, while many authors have studied a relaxation of the perfect price foresight assumption (e.g., [201, 209, 210, 211, 214, 232]), less attention is given to the study of the price-effect of storage transactions.

First, [201, 215] consider the price-effect monthly through the slope of an observed linear relationship between the system load and price. Second, [32] uses a similar methodology, by introducing a constant slope for the entire year to represent the price-effect. Third, [216] and [217] relax the price-taking assumption by considering the residual inverse demand curve. In [216] the price-effect is defined by a residual inverse demand curve that depends on the slopes of the demand and supply curves, and which is modeled as an approximated sigmoid function. In contrast, in [217], the mirrored image of the stepwise supply curve from other generators is assumed to represent the residual inverse demand curve, with the demand curve assumed to be perfectly inelastic. Refs. [233] and [234] employ a similar methodology, with the latter linearizing the stepwise supply curve. Whereas the former works introduce inaccuracies by neglecting (1) the time-varying aggregated supply and demand curves, (2) the presence of and change in acceptance or rejection of complex orders, and (3) changes in cross-border flows, [9] considers the most accurate available price-effect data. It is published by several European power exchanges in the form of hourly piecewise linear relationships between quantity and price. These are referred to as DA market resilience functions, and show to which extent additional demand and supply would affect the price. It is obtained by rerunning the market-clearing algorithm for different variations of additional offer or demand volume at any price, and takes into account the (1) aggregated supply and demand curves, (2) presence and dynamics of complex orders, and (3) cross-border interaction through market-coupling.

Co-optimization of applications

The existing literature considering multi-service portfolios for storage can also be categorized according to the adopted approach, i.e., a system perspective or PBUC storage operator perspective. The former studies the degree to which storage plants, employed for multiple applications, contribute to minimizing total system cost (e.g., [34, 56, 83, 87]), while the latter focuses on maximizing the value of the considered storage plant. Most PBUC work underestimates the storage value due to the focus on only a single application. Furthermore, most of the studies that do focus on the aggregation of different applications, do not allocate the storage resources by means of a continuous optimization process. Determining the true value of storage requires the aggregation of multiple applications while accounting for the interdependence between revenue streams. The latter means that the value of individual applications cannot simply be added, but need to be co-optimized since different services can interfere with one another.

However, some recent studies focus on co-optimizing the scheduling for different applications by the storage operator. Ref. [33] maximizes the storage value while simultaneously focusing on DA market arbitrage, congestion management, and frequency control. Ref. [235] is related to the former study as it focuses on the same set of services and includes a similar model, but focuses on the impact of battery degradation. In [192], the storage scheduling for DA market arbitrage, frequency control, back-up provision, and congestion management is co-optimized, while [236] uses a similar model but includes a more detailed representation of the operating constraints. Ref. [237] studies a multi-application operation of storage including DA market arbitrage and the provision of frequency control, with [230] focusing on the same set of services but applied to CAES specifically. In [238], a storage plant is assumed to participate in the DA and RT markets, and provides upward frequency control. Ref. [239] studies the combined storage value for supporting a large consumer and RES generation system, and providing grid services such as frequency control and congestion management to the system operator.

Applications cannot only be aggregated for a certain storage plant by one market player, but also over multiple market participants. The sharing of storage resources by different players has only been studied to a limited extent.

Ref. [32] studies a sequential allocation of storage resources to players which express their need for storage at different time scales. Ref. [13] further builds on this work by introducing the concept of physical storage rights, to allocate the right to use storage resources among different players simultaneously through an auction-based mechanism. In addition, [240] provides additional insights in this topic, but assigns different meanings to the introduced storage rights, and focuses on this multi-player operation as a way for storage to overcome regulatory barriers. Finally, in [241], different users located on the same site share a storage system for a combination of services, which can generally be categorized as portfolio management for large consumers and RES generators.

6.1.3 Scope and contributions

This chapter contributes to the current literature on electricity storage valuation in short-term markets through three aspects. First, we provide model formulations that allow to aggregate multiple arbitrage opportunities for electricity storage in a single operating strategy, and to quantify the accompanying potential arbitrage value. We consider all three short-term markets, i.e., the DA, ID, and RT balancing market, and we consider the opportunity to capture three types of price differences: (1) over time in a single market for all three markets, (2) over the three short-term markets for the same market period, and (3) over time over the three short-term markets. The developed models do not a priori allocate a storage plant's power and energy ratings across the three short-term markets and three arbitrage types, but allocate the storage resources for each time step according to a daily performed multiperiod optimization. Second, the price-effect of actions of additional storage capacity has been considered before in the literature for the DA market with various levels of detail, but not for the ID or RT balancing market. We contribute by studying the price-effect with high detail for not only the DA market, but also for the ID market, and for the RT balancing market by using custom-made piecewise linear RT market resilience functions based on real-world data. Third, we apply the developed models to the four market zones of the CWE region, i.e., the Belgian, French, German, and Dutch market zones, for a full year using price and volume data from these markets. As such, we provide insight in the extent to which the three short-term markets, and their combination, in these market zones are potentially interesting for electricity storage arbitrage. This is intended to support market participants in electricity storage investment and operation decisions, and to inform policy-makers about the impact of market design rules on the electricity storage arbitrage potential.

6.2 Electricity storage arbitrage in short-term electricity markets

6.2.1 Short-term electricity markets

Day-ahead market

In the DA market, which is fully harmonized across the CWE region, players can submit buy and sell quantity-price bids on a 1 h basis to change their position from the previously held long-term markets. These bids can be submitted until DA market closure, i.e., noon (12:00 pm) the day before delivery (D-1), for each hour of delivery day D. All submitted demand and supply bids are aggregated, with the intersection determining the market-clearing volume and price: all cleared demand bids in a market zone pay this price, while all cleared supply bids in a market zone receive this price, i.e., pay-as-cleared. While DA market trading within market zones is not constrained by the grid capacity, its interaction with neighboring zones is [6, 11, 149].

In Europe, currently 23 countries, including the CWE region, are coupled through the implicit auctioning of interconnection capacity: all bids of the different exchanges are considered in the same market-clearing algorithm to optimize the utilization of interconnection capacity available to the power exchanges [158]. Market players only provide bids for electric energy, while interconnection capacity is allocated implicitly to individual bids to maximize social welfare. As a result, electric energy is exchanged in case of a price difference between neighboring markets until the price difference is eliminated or until all available interconnection capacity is used [9, 160].

Intra-day market

ID markets are organized to adjust positions based on updated expectations. Although they are currently still characterized by low liquidity in the CWE region, they are becoming increasingly important [6]. Trading in the ID market is the last opportunity for market-based transactions before the submitted schedules (or “nominations”) become financially binding. Nominations are not physically binding, as RT deviations from scheduled positions (i.e., imbalances) are settled at the imbalance price.

While the Belgian, Dutch, and French ID markets are based on continuous trading with 1 h products, the German ID market includes both continuous trading (with both 1 h and 15 min products) and a discrete auction with 15 min market periods. With continuous trading, bids are submitted to a central platform, and matching pairs are continuously cleared on an individual basis. Trading is possible from 02:00 pm D-1 in Belgium, and from 03:00 pm D-1 in France, Germany, and the Netherlands, and can occur until close to RT. The discrete auction, implemented in the German ID market since December 2014, with market closure at 03:00 pm D-1, is based on principles similar to the DA market [111, 138].

In the CWE region, ID markets are currently less well harmonized and integrated than DA markets, and only the residual interconnection capacity after DA trading can be used. In the ID market, explicit allocation of interconnection capacity allows players to obtain remaining interconnection capacity for free as long as capacity is available. However, in case the obtained capacity is not used, this unfulfilled position is settled at the imbalance price since allocated cross-border capacity is automatically nominated [173]. With implicit allocation, orders in one zone are automatically matched with orders in the neighboring zone, given the remaining transmission capacity. At the different borders of the CWE region currently a mix of explicit and implicit allocation applies, but a move can be observed from the former to the latter [6].

Real-time balancing market

In the RT balancing market the TSO contracts and activates reserve capacity from BSPs at the reserve procurement side, and settles imbalance positions with BRPs at the imbalance settlement side. We focus on the imbalance settlement as a possibly attractive market for storage to participate in. It is based on 15 min market periods in Belgium, Germany, and the Netherlands, and 30 min periods in France [6].

At the settlement side of the balancing market, BRP imbalance positions and the control area's imbalance prices are determined. Imbalance positions refer to the difference between BRP positions after ID market closure and RT net exchanges with the grid. A long position indicates a positive imbalance, with more injection and/or less offtake than scheduled, while a short position indicates a negative imbalance, with less injection and/or more offtake. BRPs with a long position receive the long imbalance price, while BRPs with a short position pay the short imbalance price [146]. Through this settlement, the TSO allocates the activation cost of reserves to responsible BRPs, while reservation costs to contract reserves are recovered via grid tariffs.

Imbalance prices are calculated through either a dual or single-pricing scheme. With dual-pricing, the imbalance price applied to BRP imbalances in the same direction as the SI is based on the activation cost of reserves, while the imbalance price applied to those in the opposite direction of the SI is (typically) based on the DA price. In contrast, in a single-pricing scheme, a uniform imbalance price, based on the activation cost of reserves, is applied to all BRPs with a long or short position. In France, a dual-pricing scheme is implemented, and in Belgium, Germany, and the Netherlands single-pricing applies [103]. However, in case both up and downward reserves are activated the prices differ in the Netherlands: the long imbalance price is based on the activation price for downward reserve while the short imbalance price is based on that for upward reserve. In addition, in Belgium and the Netherlands, the imbalance price applied to short and long positions differs in the event of large SIs by including a balance-incentivizing component, to either punish BRP imbalances in the same direction as the SI or to incentivize all BRPs. Although such a component is applied in Germany as well, it does not result in different prices: the price is increased for all BRPs in case the SI is negative, and decreased in case the SI is positive [119].

When the imbalance price reflects the procurement cost of activated reserves, it is either based on the marginal or average activation price. With marginal pricing, the imbalance price is set to the price of the marginal accepted bid, while for average pricing it is calculated by dividing the net total activation costs of the TSO by the net activated reserve volume. The imbalance price is based on marginal pricing in Belgium and the Netherlands, while France and Germany apply average pricing [146, 115, 113, 143].

6.2.2 Electricity storage arbitrage

Classic definitions of arbitrage denote making a riskless profit by simultaneously buying and selling a similar commodity with net zero investment [28]. However, any activity in which a player buys a commodity and sells a similar commodity, or one in which the former can be converted, at a higher price for profit can be referred to as arbitrage. This definition allows to include initial investments, does not require simultaneity of the purchase and sale, and furthermore does not restrict to a single commodity either [9].

We distinguish four types of arbitrage in electricity markets: intertemporal, interzonal, intermarket, and intercommodity (Fig. 6.1). With intertemporal arbitrage, electricity price differences are captured over time, while interzonal arbitrage refers to the capturing of price spreads between adjacent market zones. Intermarket arbitrage refers to the activity in which virtual bidders profit from price differences between different (sequentially organized) electricity markets by making trades in the opposite direction to cancel outstanding positions. Finally, intercommodity arbitrage is based on price differences between fuel and electricity. These four basic arbitrage types can also be combined leading to hybrid types, e.g., intertemporal intermarket arbitrage is the capturing of electricity price spreads over time over different markets. In this chapter, electricity storage arbitrage refers to considering intertemporal, intermarket, and intertemporal intermarket arbitrage.

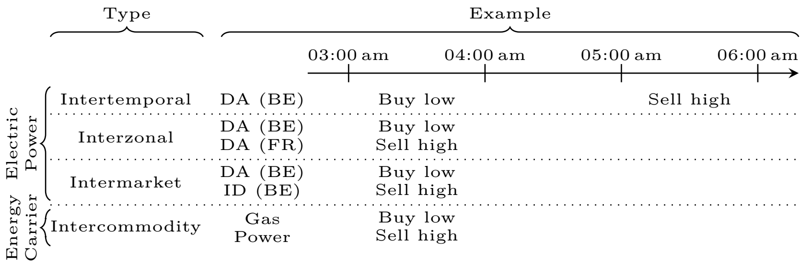


Figure 6.1: Arbitrage in electricity markets.

Aside from the operational flexibility of the considered storage plant, which is determined by its start-up and shut-down cost, minimum load requirements, ramp rates and cost, and minimum up and down times, we define four factors related to the combination of storage technology, storage sizing, and market parameters, that determine the profitability of electricity storage arbitrage.

1. The price spread between the buy price λ_t^{b} and sell price λ_t^{s}, and the cost due to energy losses if physical (dis)charge actions are required (i.e., with intertemporal and intertemporal intermarket arbitrage). The cost due to losses to arbitrage one unit of energy is calculated as $(1/\eta^{\mathrm{rt}} - 1) \cdot \lambda_t^{\mathrm{b}}$, with η^{rt} the roundtrip efficiency.

2. The price profile, and the (dis)charge duration. Two price profiles, containing identical prices but in a different order, result in different arbitrage profits in case the (dis)charge duration is limiting the optimal operation. E.g., a limited duration can cause the storage to be fully charged prematurely in times of consistent low prices, making it impossible to capture all present arbitrage opportunities.

3. The uncertainty and predictability of λ_t^{b} and λ_t^{s}. In the DA market, which is the most studied market for storage arbitrage, the uncertainty used to be much lower, and the predictability much higher, because of clear daily and weekly patterns of the system load and prices. However, the ongoing energy transition makes prices more uncertain as the historically clear patterns are becoming less obvious. This is even more challenging for ID prices and especially RT imbalance prices.

4. The price-effect, and the buy and sell volume. Typically, additional buy transactions increase λ_t^{b}, and additional sell transactions decrease λ_t^{s}. This price-effect is generally negligible for transactions that are small compared to the market size, but can be significant for large-scale storage transactions. Taking this into account results in a trade-off between the remaining price spread and transaction size.

6.3 Electricity storage arbitrage model formulations

6.3.1 Methodology and model setup

Whereas the scheduling of capacity to meet the load at minimum cost is referred to as cost-based UC, scheduling to maximize profit based on price signals is referred to as PBUC [194]. In this chapter a PBUC perspective is used to quantify the potential electricity storage arbitrage value under different assumptions and scenarios. We consider the storage operator's participation in the DA market, ID market, and RT market's settlement side, and study two strategies: separate (Section 6.3.2) and coordinated participation (Section 6.3.3). Separate participation refers to considering each market separately and sequentially, whereas coordinated participation indicates that at each decision stage all markets that are still to be held are considered simultaneously. For each strategy, the problem that the operator faces in the DA stage, ID stage, and RT stage is described. We define the DA stage to take place before DA market closure (i.e., $\leq$ 12:00 pm D-1), the ID stage after the DA stage and before the start of the optimization period (i.e., DA stage $\leq$ and $\leq$ 12:00 am D), and the RT stage after the ID stage and before the start of the optimization period (i.e., ID stage $\leq$ and $\leq$ 12:00 am D).

The continuous time dimension is discretized, with q the discrete 15 min time index and T^{q} the fixed time step length of 15 min (Fig. 6.2). The storage operator maximizes the operating profit from electricity storage arbitrage on a daily basis. In order to ensure that energy stored at the end of each daily optimization period has carryover value [9, 201], each optimization is done with a two-day horizon, i.e., 192 15 min time steps ($\forall\, q \in \mathbb{Q}$), to determine the (trans)actions in the 96 15 min periods of each day D.

The included base case model formulations for separate and coordinated participation assume a perfect foresight and no impact on prices. As such, we quantify the electricity storage arbitrage potential in case (1) the (trans)actions of the additional storage capacity are small compared to the size of the market, or (2) the prices to already include the storage plant's price-taking participation. They are applied to the four market zones of the CWE region. Afterwards, we include the price-effect in a case study for Belgium, to analyze its impact and quantify the upper limit to the storage arbitrage value for additional large-scale storage resources.[1]

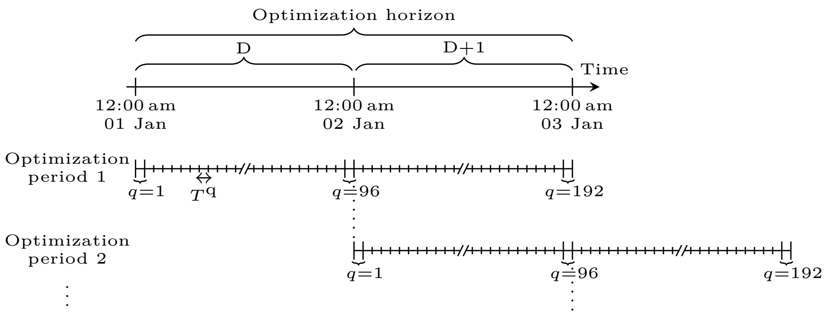


Figure 6.2: Time dimension discretization and rolling optimization horizon.

In the model formulations storage plants are characterized by a minimum and maximum (dis)charge power rating and energy storage capacity, (dis)charge efficiency, down and upward ramp rate in (dis)charge mode, and targeted cycling rate. Although there is no direct constraint on the number of cycles during each optimization period, due to the limited cycle-life it is implied that the targeted cycling rate is constant throughout the calendar life. If the cycling rate is lower than or equal to the targeted cycling rate, the depreciation cost resulting from cycling is zero, otherwise it is positive (Fig. 6.3). The formulation to include the cycle-life and depreciation cost is based on [9], and originally derived from [92]. Furthermore, this chapter assumes changes in the buffered energy due to exogenous power flows (e.g., self-discharge) to be negligible in the short-term.

Finally, the formulated optimization problems are MILPs, which are modeled in GAMS [242] and solved using the CPLEX solver [227]. All models are solved to optimality by setting the GAMS option "optcr" to zero.

[1] While when participating in a certain market (e.g., DA market) there may be a price-effect in another market (e.g., ID market) as well, which we label as cross-market price-effects, this chapter focuses on price-effects in the same market, which can be referred to as own-market price-effects.

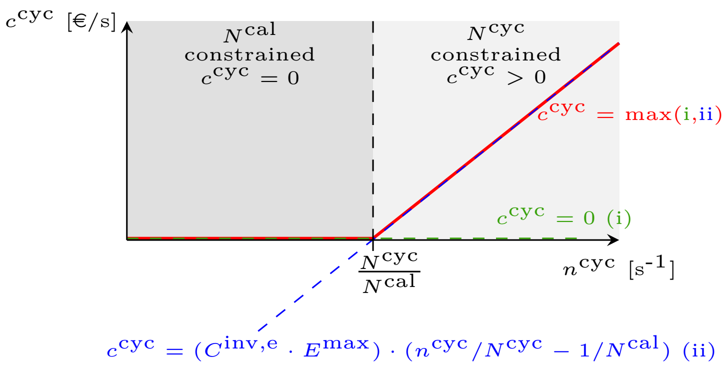


Figure 6.3: Opportunity cost for wearing out the energy storage subsystem [9].

6.3.2 Separate participation - no price-effect

Day-ahead stage (problem I)

With separate participation, at the DA stage the storage operator maximizes the operating profit resulting from participation in the DA market (6.1). Its market-based transactions $p_q^{\mathrm{b,da}}$ and $p_q^{\mathrm{s,da}}$ are subject to two sets of equations: (6.2)-(6.3), and (6.4)-(6.5). The former ensure that either a buy or sell transaction can occur per time step, while respecting the power rating bounds of the physical storage asset backing the transactions. The latter enforce that the transaction in each 15 min time step of any hour is uniform, in line with the DA market's 1 h market periods. Consistently, the included 15 min DA price $\lambda_q^{\mathrm{da,o}}$ is identical for the four consecutive 15 min of any hour as well. Constraint (6.6) links the market-based transactions with the planned physical operation, with (6.7)-(6.14) representing the physics of the storage system. Constraint (6.7) expresses the intertemporal nature of electricity storage. Constraints (6.8) and (6.9) limit the change in (dis)charge power by the storage plant's ramp rates.[2] Constraints (6.10)-(6.12) represent capacity bounds on the (dis)charge power and storage capacity, with a strict separation of the electricity consumption and generation phase. The combination of the nonnegativity of c^{cyc}, (6.13)-(6.14), and the minimization of c^{cyc} in (6.1), represents the convex relaxation of the max operator illustrated in Fig. 6.3:

[2]When $q = 1$ in (6.7)-(6.9), index q-1 indicates $q = 96$ of the previous optimization period, except for the first optimization period where index q-1 at $q = 1$ refers to certain starting values.

$$
\begin{aligned}
&\pi^{\mathrm{op,da}} = \max \sum_{q \in \mathbb{Q}} \lambda_q^{\mathrm{da,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}) / (|\mathbb{Q}| \cdot T^{\mathrm{q}}) - c^{\mathrm{cyc,da}}, && (6.1)\\
\text{s.t.} \quad & 0 \leq p_q^{\mathrm{b,da}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{bs,da}}, & \forall\, q \in \mathbb{Q}, \quad & (6.2)\\
& 0 \leq p_q^{\mathrm{s,da}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{bs,da}}), & \forall\, q \in \mathbb{Q}, \quad & (6.3)\\
& p_q^{\mathrm{b,da}} = p_{q+1}^{\mathrm{b,da}} = p_{q+2}^{\mathrm{b,da}} = p_{q+3}^{\mathrm{b,da}}, & \forall\, q \in \mathbb{Q}^{\mathrm{fq}}, & (6.4)\\
& p_q^{\mathrm{s,da}} = p_{q+1}^{\mathrm{s,da}} = p_{q+2}^{\mathrm{s,da}} = p_{q+3}^{\mathrm{s,da}}, & \forall\, q \in \mathbb{Q}^{\mathrm{fq}}, & (6.5)\\
& p_q^{\mathrm{d,da}} - p_q^{\mathrm{c,da}} = p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}, & \forall\, q \in \mathbb{Q}, \quad & (6.6)\\
& e_q^{\mathrm{da}} = e_{q\text{-}1}^{\mathrm{da}} + T^{\mathrm{q}} \cdot (p_q^{\mathrm{c,da}} \cdot \eta^{\mathrm{c}} - p_q^{\mathrm{d,da}} / \eta^{\mathrm{d}}), & \forall\, q \in \mathbb{Q}, \quad & (6.7)\\
& -R^{\mathrm{c,do}} \cdot P^{\mathrm{c,max}} \leq (p_q^{\mathrm{c,da}} - p_{q\text{-}1}^{\mathrm{c,da}}) / T^{\mathrm{q}} \leq R^{\mathrm{c,up}} \cdot P^{\mathrm{c,max}}, & \forall\, q \in \mathbb{Q}, \quad & (6.8)\\
& -R^{\mathrm{d,do}} \cdot P^{\mathrm{d,max}} \leq (p_q^{\mathrm{d,da}} - p_{q\text{-}1}^{\mathrm{d,da}}) / T^{\mathrm{q}} \leq R^{\mathrm{d,up}} \cdot P^{\mathrm{d,max}}, & \forall\, q \in \mathbb{Q}, \quad & (6.9)\\
& 0 \leq P^{\mathrm{c,min}} \cdot b_q^{\mathrm{da}} \leq p_q^{\mathrm{c,da}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{da}}, & \forall\, q \in \mathbb{Q}, & (6.10)\\
& 0 \leq P^{\mathrm{d,min}} \cdot (1 - b_q^{\mathrm{da}}) \leq p_q^{\mathrm{d,da}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{da}}), & \forall\, q \in \mathbb{Q}, & (6.11)\\
& 0 \leq E^{\mathrm{min}} \leq e_q^{\mathrm{da}} \leq E^{\mathrm{max}}, & \forall\, q \in \mathbb{Q}, & (6.12)\\
& n^{\mathrm{cyc,da}} = \eta^{\mathrm{c}} \cdot \sum_{q \in \mathbb{Q}} p_q^{\mathrm{c,da}} \cdot T^{\mathrm{q}} / (E^{\mathrm{max}} \cdot |\mathbb{Q}| \cdot T^{\mathrm{q}}), && (6.13)\\
& c^{\mathrm{cyc,da}} \geq (C^{\mathrm{inv,e}} \cdot E^{\mathrm{max}}) \cdot (n^{\mathrm{cyc,da}} / N^{\mathrm{cyc}} - 1 / N^{\mathrm{cal}}), && (6.14)\\
& c^{\mathrm{cyc,da}}, e_q^{\mathrm{da}}, n^{\mathrm{cyc,da}}, p_q^{\mathrm{b,da}}, p_q^{\mathrm{c,da}}, p_q^{\mathrm{d,da}}, p_q^{\mathrm{s,da}} \in \mathbb{R}_+, &&\\
& b_q^{\mathrm{bs,da}}, b_q^{\mathrm{da}} \in \{0,1\}, \mathbb{Q}, \mathbb{Q}^{\mathrm{fq}} \subset \mathbb{N}, \mathbb{Q}^{\mathrm{fq}} \subset \mathbb{Q}, &&\\
& \mathbb{Q}^{\mathrm{fq}} = \{q \in \mathbb{Q} \,|\, q \bmod (60\,\mathrm{min}/T^{\mathrm{q}}) = 1\}, & \forall\, q \in \mathbb{Q}. & (6.15)
\end{aligned}
$$

The optimized values for $p_q^{\mathrm{b,da}}$ and $p_q^{\mathrm{s,da}}$ in problem I are afterwards derived and defined as parameters (small "p" for decision variable, corresponding capital "P" for parameter) to be used in the ID and RT stages:

$$P_q^{\mathrm{b,da}} = \arg\max_{p_q^{\mathrm{b,da}}}(\text{problem I}), P_q^{\mathrm{s,da}} = \arg\max_{p_q^{\mathrm{s,da}}}(\text{problem I}), \quad \forall q \in \mathbb{Q}. \tag{6.16}$$

Intra-day stage (problem II)

The formulation provided in (6.17)-(6.36) encompasses the most extensive ID case, i.e., the German ID market. However, it also applies to market zones in which only a subset of the three ID markets present in Germany is organized, by simply enforcing that the buy and sell transactions in the absent ID markets equal zero. With separate participation, at the ID stage the storage operator maximizes the operating profit resulting from participation in the ID market(s) (6.17). As each trade can be settled at a different price with continuous trading, we use the volume-weighted average ID price of the cleared trades in q for $\lambda_q^{\mathrm{id,ch,o}}$ and $\lambda_q^{\mathrm{id,cq,o}}$.[3] The transactions in the 1 h continuous trading ID market are subject to two sets of equations similar to the case at the DA stage, i.e., (6.19)-(6.20), and (6.25)-(6.26). In contrast, the transactions in the 15 min continuous trading and auction-based ID markets are only subject to the first set of equations, i.e., (6.21)-(6.22) and (6.23)-(6.24), respectively. Constraint (6.27) links the financial transactions with the planned physical (dis)charge actions of the storage plant, taking into account the transactions made in the previously held DA market (6.18). Finally, (6.28)-(6.35) represent the storage system's physics similar to the case at the DA stage:

$$\begin{aligned}\pi^{\mathrm{op,id}} = \max \sum_{q \in \mathbb{Q}} \Big[& \lambda_q^{\mathrm{da,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}) + \lambda_q^{\mathrm{id,ch,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,ch}} - p_q^{\mathrm{b,id,ch}}) \\ & + \lambda_q^{\mathrm{id,cq,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,cq}} - p_q^{\mathrm{b,id,cq}}) + \lambda_q^{\mathrm{id,aq,o}} \cdot T^{\mathrm{q}} \\ & \cdot (p_q^{\mathrm{s,id,aq}} - p_q^{\mathrm{b,id,aq}}) \Big] / (|\mathbb{Q}| \cdot T^{\mathrm{q}}) - c^{\mathrm{cyc,id}}, \end{aligned} \tag{6.17}$$

s.t. (6.15),

$$p_q^{\mathrm{b,da}} = P_q^{\mathrm{b,da}}, p_q^{\mathrm{s,da}} = P_q^{\mathrm{s,da}}, \qquad \forall q \in \mathbb{Q}, \tag{6.18}$$

$$0 \leq p_q^{\mathrm{b,id,ch}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{bs,id,ch}}, \qquad \forall q \in \mathbb{Q}, \tag{6.19}$$

$$0 \leq p_q^{\mathrm{s,id,ch}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{bs,id,ch}}), \qquad \forall q \in \mathbb{Q}, \tag{6.20}$$

[3] Parameter $\lambda_q^{\mathrm{id,ch,o}}$ is identical for the four consecutive 15 min of any hour.

$$0 \leq p_q^{\mathrm{b,id,cq}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{bs,id,cq}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.21)$$

$$0 \leq p_q^{\mathrm{s,id,cq}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{bs,id,cq}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.22)$$

$$0 \leq p_q^{\mathrm{b,id,aq}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{bs,id,aq}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.23)$$

$$0 \leq p_q^{\mathrm{s,id,aq}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{bs,id,aq}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.24)$$

$$p_q^{\mathrm{b,id,ch}} = p_{q+1}^{\mathrm{b,id,ch}} = p_{q+2}^{\mathrm{b,id,ch}} = p_{q+3}^{\mathrm{b,id,ch}}, \qquad \forall\, q \in \mathbb{Q}^{\mathrm{fq}}, \ (6.25)$$

$$p_q^{\mathrm{s,id,ch}} = p_{q+1}^{\mathrm{s,id,ch}} = p_{q+2}^{\mathrm{s,id,ch}} = p_{q+3}^{\mathrm{s,id,ch}}, \qquad \forall\, q \in \mathbb{Q}^{\mathrm{fq}}, \ (6.26)$$

$$\begin{aligned} p_q^{\mathrm{d,id}} - p_q^{\mathrm{c,id}} = {} & p_q^{\mathrm{s,id,ch}} + p_q^{\mathrm{s,id,cq}} + p_q^{\mathrm{s,id,aq}} + p_q^{\mathrm{s,da}} \\ & - p_q^{\mathrm{b,id,ch}} - p_q^{\mathrm{b,id,cq}} - p_q^{\mathrm{b,id,aq}} - p_q^{\mathrm{b,da}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.27) \end{aligned}$$

$$e_q^{\mathrm{id}} = e_{q\text{-}1}^{\mathrm{id}} + T^{\mathrm{q}} \cdot (p_q^{\mathrm{c,id}} \cdot \eta^{\mathrm{c}} - p_q^{\mathrm{d,id}}/\eta^{\mathrm{d}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.28)$$

$$-R^{\mathrm{c,do}} \cdot P^{\mathrm{c,max}} \leq (p_q^{\mathrm{c,id}} - p_{q\text{-}1}^{\mathrm{c,id}})/T^{\mathrm{q}} \leq R^{\mathrm{c,up}} \cdot P^{\mathrm{c,max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.29)$$

$$-R^{\mathrm{d,do}} \cdot P^{\mathrm{d,max}} \leq (p_q^{\mathrm{d,id}} - p_{q\text{-}1}^{\mathrm{d,id}})/T^{\mathrm{q}} \leq R^{\mathrm{d,up}} \cdot P^{\mathrm{d,max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.30)$$

$$0 \leq P^{\mathrm{c,min}} \cdot b_q^{\mathrm{id}} \leq p_q^{\mathrm{c,id}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{id}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.31)$$

$$0 \leq P^{\mathrm{d,min}} \cdot (1 - b_q^{\mathrm{id}}) \leq p_q^{\mathrm{d,id}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{id}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.32)$$

$$0 \leq E^{\mathrm{min}} \leq e_q^{\mathrm{id}} \leq E^{\mathrm{max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.33)$$

$$n^{\mathrm{cyc,id}} = \eta^{\mathrm{c}} \cdot \sum_{q \in \mathbb{Q}} p_q^{\mathrm{c,id}} \cdot T^{\mathrm{q}} / (E^{\mathrm{max}} \cdot |\mathbb{Q}| \cdot T^{\mathrm{q}}), \qquad (6.34)$$

$$c^{\mathrm{cyc,id}} \geq (C^{\mathrm{inv,e}} \cdot E^{\mathrm{max}}) \cdot (n^{\mathrm{cyc,id}}/N^{\mathrm{cyc}} - 1/N^{\mathrm{cal}}), \qquad (6.35)$$

$$\begin{aligned} & c^{\mathrm{cyc,id}}, e_q^{\mathrm{id}}, n^{\mathrm{cyc,id}}, p_q^{\mathrm{b,id,ch}}, p_q^{\mathrm{b,id,cq}}, p_q^{\mathrm{b,id,aq}}, p_q^{\mathrm{c,id}}, \\ & p_q^{\mathrm{d,id}}, p_q^{\mathrm{s,id,ch}}, p_q^{\mathrm{s,id,cq}}, p_q^{\mathrm{s,id,aq}} \in \mathbb{R}_+, \\ & b_q^{\mathrm{bs,id,ch}}, b_q^{\mathrm{bs,id,cq}}, b_q^{\mathrm{bs,id,aq}}, b_q^{\mathrm{id}} \in \{0, 1\}, \qquad \forall\, q \in \mathbb{Q}. \quad (6.36) \end{aligned}$$

The optimized values for $p_q^{\mathrm{b,id,ch}}$, $p_q^{\mathrm{b,id,cq}}$, $p_q^{\mathrm{b,id,aq}}$, $p_q^{\mathrm{s,id,ch}}$, $p_q^{\mathrm{s,id,cq}}$, $p_q^{\mathrm{s,id,aq}}$, $p_q^{\mathrm{c,id}}$, and $p_q^{\mathrm{d,id}}$ in problem II are, similar to (6.16), derived and defined as parameters (e.g., $P_q^{\mathrm{b,id,ch}}$) to be used in the RT stage.

Real-time stage (problem III)

By arbitraging imbalance prices, BRPs typically reduce the amount of activated reserves, here represented by the NRV, which is generally small compared to the DA market trading volume and system load. This is done by intentionally incurring imbalances in the opposite direction of the SI, as for this direction the imbalance price is more favorable than in the same direction of the SI. This can be referred to as "passive balancing", which helps the TSO to keep the balance. While dual-pricing provides little incentive for passive balancing, since the DA price is applied to imbalances in the opposite direction of the SI, single-pricing does.

- If SI < 0, the TSO activates upward reserve, i.e., NRV > 0. Typically, this is activated at a price higher than the DA price, and more activated upward reserve results in a higher imbalance price, as it is selected according to a merit-order of increasing activation prices. This incentivizes BRPs to have a long position.
- If SI > 0, the TSO activates downward reserve, i.e., NRV < 0. Typically, this is activated at a price lower than the DA price, and more activated downward reserve results in a lower imbalance price, as it is selected according to a merit-order of decreasing activation prices. This incentivizes BRPs to have a short position.

The storage operator faces the RT arbitrage problem at the RT stage (6.37). The operator can either follow its submitted nomination, indicated by the planned (dis)charge actions after the ID stage, which are the result of DA and ID market trading (6.18), (6.38), or incur an imbalance position (6.41). Such an imbalance can either be positive or negative (6.39)-(6.40), and is incurred according to expected imbalance prices. Again, the planned (dis)charge actions are subject to the physics of the storage system (6.42)-(6.49):

$$\begin{aligned}\pi^{\mathrm{op,rt}} = \max \sum_{q \in \mathbb{Q}} \Big[& \lambda_q^{\mathrm{da,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}) + \lambda_q^{\mathrm{id,ch,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,ch}} - p_q^{\mathrm{b,id,ch}}) \\ & + \lambda_q^{\mathrm{id,cq,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,cq}} - p_q^{\mathrm{b,id,cq}}) + \lambda_q^{\mathrm{id,aq,o}} \cdot T^{\mathrm{q}} \\ & \cdot (p_q^{\mathrm{s,id,aq}} - p_q^{\mathrm{b,id,aq}}) + \lambda_q^{\mathrm{rt,+,o}} \cdot T^{\mathrm{q}} \cdot p_q^{\mathrm{i,+}} - \lambda_q^{\mathrm{rt,\text{-},o}} \cdot T^{\mathrm{q}} \cdot p_q^{\mathrm{i,\text{-}}} \Big] \\ & /(|\mathbb{Q}| \cdot T^{\mathrm{q}}) - c^{\mathrm{cyc,rt}}, \end{aligned} \tag{6.37}$$

s.t. (6.15),(6.18),(6.36),

$$p_q^{\mathrm{b,id,ch}} = P_q^{\mathrm{b,id,ch}}, p_q^{\mathrm{b,id,cq}} = P_q^{\mathrm{b,id,cq}}, p_q^{\mathrm{b,id,aq}} = P_q^{\mathrm{b,id,aq}},$$

$$p_q^{\mathrm{s,id,ch}} = P_q^{\mathrm{s,id,ch}}, p_q^{\mathrm{s,id,cq}} = P_q^{\mathrm{s,id,cq}}, p_q^{\mathrm{s,id,aq}} = P_q^{\mathrm{s,id,aq}},$$

$$p_q^{\mathrm{c,id}} = P_q^{\mathrm{c,id}}, p_q^{\mathrm{d,id}} = P_q^{\mathrm{d,id}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.38)$$

$$p_q^{\mathrm{i,+}} \leq P^{\mathrm{i,max}} \cdot b_q^{\mathrm{i}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.39)$$

$$p_q^{\mathrm{i,\text{-}}} \leq P^{\mathrm{i,max}} \cdot (1 - b_q^{\mathrm{i}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.40)$$

$$p_q^{\mathrm{d,rt}} - p_q^{\mathrm{d,id}} - p_q^{\mathrm{c,rt}} + p_q^{\mathrm{c,id}} = p_q^{\mathrm{i,+}} - p_q^{\mathrm{i,\text{-}}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.41)$$

$$e_q^{\mathrm{rt}} = e_{q\text{-}1}^{\mathrm{rt}} + T^{\mathrm{q}} \cdot (p_q^{\mathrm{c,rt}} \cdot \eta^{\mathrm{c}} - p_q^{\mathrm{d,rt}} / \eta^{\mathrm{d}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.42)$$

$$-R^{\mathrm{c,do}} \cdot P^{\mathrm{c,max}} \leq (p_q^{\mathrm{c,rt}} - p_{q\text{-}1}^{\mathrm{c,rt}}) / T^{\mathrm{q}} \leq R^{\mathrm{c,up}} \cdot P^{\mathrm{c,max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.43)$$

$$-R^{\mathrm{d,do}} \cdot P^{\mathrm{d,max}} \leq (p_q^{\mathrm{d,rt}} - p_{q\text{-}1}^{\mathrm{d,rt}}) / T^{\mathrm{q}} \leq R^{\mathrm{d,up}} \cdot P^{\mathrm{d,max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.44)$$

$$0 \leq P^{\mathrm{c,min}} \cdot b_q^{\mathrm{rt}} \leq p_q^{\mathrm{c,rt}} \leq P^{\mathrm{c,max}} \cdot b_q^{\mathrm{rt}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.45)$$

$$0 \leq P^{\mathrm{d,min}} \cdot (1 - b_q^{\mathrm{rt}}) \leq p_q^{\mathrm{d,rt}} \leq P^{\mathrm{d,max}} \cdot (1 - b_q^{\mathrm{rt}}), \qquad \forall\, q \in \mathbb{Q}, \quad (6.46)$$

$$0 \leq E^{\mathrm{min}} \leq e_q^{\mathrm{rt}} \leq E^{\mathrm{max}}, \qquad \forall\, q \in \mathbb{Q}, \quad (6.47)$$

$$n^{\mathrm{cyc,rt}} = \eta^{\mathrm{c}} \cdot \sum_{q \in \mathbb{Q}} p_q^{\mathrm{c,rt}} \cdot T^{\mathrm{q}} / (E^{\mathrm{max}} \cdot |\mathbb{Q}| \cdot T^{\mathrm{q}}), \quad (6.48)$$

$$c^{\mathrm{cyc,rt}} \geq (C^{\mathrm{inv,e}} \cdot E^{\mathrm{max}}) \cdot (n^{\mathrm{cyc,rt}} / N^{\mathrm{cyc}} - 1 / N^{\mathrm{cal}}), \quad (6.49)$$

$$c^{\mathrm{cyc,rt}}, e_q^{\mathrm{rt}}, n^{\mathrm{cyc,rt}}, p_q^{\mathrm{c,rt}}, p_q^{\mathrm{d,rt}}, p_q^{\mathrm{i,+}}, p_q^{\mathrm{i,\text{-}}} \in \mathbb{R}_+,$$

$$b_q^{\mathrm{i}}, b_q^{\mathrm{rt}} \in \{0, 1\}, \qquad \forall\, q \in \mathbb{Q}. \quad (6.50)$$

In case the settlement side of the French RT balancing is considered, the included 15 min RT imbalance prices are identical for the two consecutive 15 min of any half-hour.

6.3.3 Coordinated participation - no price-effect

Day-ahead stage (problem IV)

With coordinated participation, at the DA stage the storage operator already takes into account the ID market and RT balancing market when deciding on transactions in the DA market, i.e., the combined operating profit is maximized (6.37). The transactions in the DA market and planned ID market transactions are, similar to the case with separate participation, constrained by (6.2)-(6.5) and (6.19)-(6.26), respectively. In addition, the nominations after the DA and ID stage also have to satisfy the physical constraints of the storage plant, i.e., (6.6)-(6.14) and (6.27)-(6.35), respectively. The operator can either plan to operate the storage plant according to its nominated position resulting from DA and planned ID trading, or to incur an imbalance position in RT according to expected imbalance prices (6.39)-(6.41). The planned physical operation at the (future) RT stage is again subject to (6.42)-(6.49).

The optimized values for $p_q^{\mathrm{b,da}}$ and $p_q^{\mathrm{s,da}}$ in problem IV are afterwards again derived and defined as parameters to be used in the ID and RT stages.

Intra-day stage (problem V)

When deciding on ID market transactions at the ID stage in case of coordinated participation, the storage operator already considers the settlement side of the RT balancing market (6.37). Again, these ID market transactions are constrained by (6.19)-(6.35). The operator can either plan to operate the storage plant according to its nominated position resulting from performed DA trading (6.18) and planned ID trading, or to incur an imbalance in RT (6.39)-(6.41). The planned physical operation at the (future) RT stage is again subject to (6.42)-(6.49).

Similar to the case of separate participation, the optimized values for $p_q^{\mathrm{b,id,ch}}$, $p_q^{\mathrm{b,id,cq}}$, $p_q^{\mathrm{b,id,aq}}$, $p_q^{\mathrm{s,id,ch}}$, $p_q^{\mathrm{s,id,cq}}$, $p_q^{\mathrm{s,id,aq}}$, $p_q^{\mathrm{c,id}}$, and $p_q^{\mathrm{d,id}}$ in problem V are derived and defined as parameters, to use them in the RT stage.

Real-time stage (problem VI)

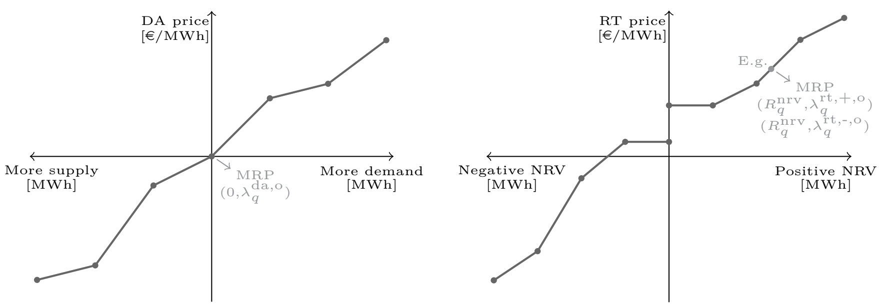
The storage operator faces a similar optimization problem as in the RT stage with separate participation, i.e., objective function (6.37) subject to (6.39)-(6.49), but now with the DA transactions decided upon in problem IV (6.18), and ID transactions and (dis)charge actions determined in problem V (6.38).

6.3.4 Considering the price-effect of storage actions

In this section we provide model formulations for the separate participation case. However, in combination with the formulations in Section 6.3.3, the price-effect models for coordinated participation can be straightforwardly derived as well.

Day-ahead stage (problem VII)

Ref. [9] relaxes the price-taking assumption in the DA market by considering hourly piecewise linear market resilience functions (Fig. 6.4a), which show the degree to which additional demand and supply would affect the DA price. They are obtained by rerunning the market-clearing algorithm for different scenarios (e.g., for Belgium this is for 50 MWh, 250 MWh, 500 MWh) of additional offer or demand volume at any price. Using this data in the arbitrage problem leads to an upper limit to the arbitrage value for additional large-scale storage capacity, under the assumption that prices and price-effects are known at the decision stage. Since the piecewise linear nature of the market resilience data poses computational challenges, i.e., the resulting problem is a nonconvex MIQP, a stepwise approximation is proposed to convert the problem into an MILP, which is easier to solve as it offers trade-offs in accuracy vs. computation time. This reduces computational efforts significantly while having the ability to provide accurate approximations of the piecewise linear result (Fig. 6.5).



(a) DA market. (b) RT market.

Figure 6.4: Available price-effect data for the Belgian DA and RT markets. The MRP refers to the situation without participation of the additional storage capacity.

This method approximates each linear segment of the piecewise linear functions by a stepwise function with identical step heights $S^{\text{tar,da}}$, with $N_{q,k}^{\text{sw,da}} \in \mathbb{N}_0$ the number of steps to approximate the linear segment between a piecewise linear function's breakpoints k and $k+1$. The resulting time-varying stepwise function's total number of steps $\sum_{k \in \mathbb{K}^{\text{da}} \setminus \{|\mathbb{K}^{\text{da}}|\}} N^{\text{sw,da}}_{q,k}$ relates to the preferred trade-off between computation time and approximation error (i.e., the larger the step height, the shorter the computation time, but the larger the error).

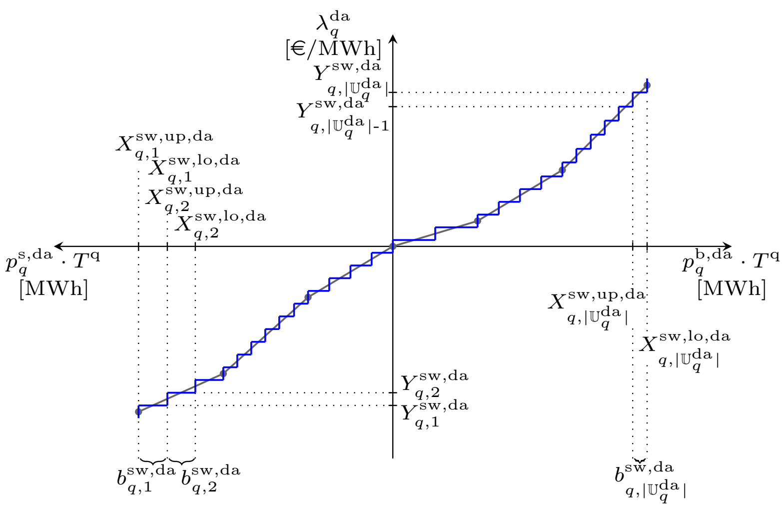


Figure 6.5: Centered stepwise approximation of the piecewise linear DA market resilience functions.

The separate participation's DA stage objective function (6.1) is updated to (6.51), with $p^{\text{b,da}}_{q,u}$ and $p^{\text{s,da}}_{q,u}$ the DA market transactions, and $Y^{\text{sw,da}}_{q,u}$ the DA price, that correspond to step u. Constraints (6.54)-(6.55) force the storage operator to be situated at one of the steps, and its DA market transaction's volume to be situated within the volume limits of that step, while (6.52)-(6.53) link the updated problem formulation to (6.2)-(6.14).

$$\pi^{\text{op,da}} = \max \sum_{q \in \mathbb{Q}} \sum_{u \in \mathbb{U}^{\text{da}}_q} Y^{\text{sw,da}}_{q,u} \cdot T^{\text{q}} \cdot (p^{\text{s,da}}_{q,u} - p^{\text{b,da}}_{q,u}) / (|\mathbb{Q}| \cdot T^{\text{q}}) - c^{\text{cyc,da}}, \quad (6.51)$$

s.t. (6.2)-(6.15),

$$\sum_{u \in \mathbb{U}^{\text{da}}_q} p^{\text{b,da}}_{q,u} = p^{\text{b,da}}_q, \qquad \forall\, q \in \mathbb{Q}, \qquad (6.52)$$

$$\sum_{u \in \mathbb{U}^{\text{da}}_q} p^{\text{s,da}}_{q,u} = p^{\text{s,da}}_q, \qquad \forall\, q \in \mathbb{Q}, \qquad (6.53)$$

$$b_{q,u}^{\mathrm{sw,da}} \cdot X_{q,u}^{\mathrm{sw,lo,da}} \leq T^{\mathrm{q}} \cdot (p_{q,u}^{\mathrm{s,da}} - p_{q,u}^{\mathrm{b,da}})$$

$$\leq b_{q,u}^{\mathrm{sw,da}} \cdot X_{q,u}^{\mathrm{sw,up,da}}, \qquad \forall\, q \in \mathbb{Q}, u \in \mathbb{U}_q^{\mathrm{da}}, \tag{6.54}$$

$$\sum_{u \in \mathbb{U}_q^{\mathrm{da}}} b_{q,u}^{\mathrm{sw,da}} = 1, \qquad \forall\, q \in \mathbb{Q}, \tag{6.55}$$

$$p_{q,u}^{\mathrm{b,da}}, p_{q,u}^{\mathrm{s,da}} \in \mathbb{R}_+\,,\, b_{q,u}^{\mathrm{sw,da}} \in \{0,1\}\,,$$

$$\mathbb{U}_q^{\mathrm{da}} = \{1, 2, ..., \sum_{k \in \mathbb{K}^{\mathrm{da}} \setminus \{|\mathbb{K}^{\mathrm{da}}|\}} N_{q,k}^{\mathrm{sw,da}}\}, \quad \forall\, q \in \mathbb{Q}, u \in \mathbb{U}_q^{\mathrm{da}}. \tag{6.56}$$

Again, the optimized values for $p_q^{\mathrm{b,da}}$ and $p_q^{\mathrm{s,da}}$ in problem VII are derived to be used as input parameters in the ID and RT stages, as are those for $b_{q,u}^{\mathrm{sw,da}}$ ($b_{q,u}^{\mathrm{sw,da}}$ for decision variable, corresponding $B_{q,u}^{\mathrm{sw,da}}$ for input parameter).

Intra-day stage (problem VIII)

In theory, the principle of the above discussed resilience functions can be mimicked for the continuous trading ID market, by considering all submitted supply and demand bids and ranking them in order of attractiveness. However, this does not take into account the fact that these bids may have been submitted any time in between ID market opening and market closure, and the presence of block orders. In addition, it is not possible to construct such functions since only data on cleared bid pairs is made available, not on nonmatched submitted bids. In the absence of ID price-effect data, we impose an upper limit $V_q^{\mathrm{id,ch}}$ to the transaction volume at the included ID price to, in some way, include the price-effect problem that large-scale storage operators face.[4] This limit represents the total volume of the cleared bids in q, which are also used to calculate the included volume-weighted average ID price:

$$\pi^{\mathrm{op,id}} = \max \sum_{q \in \mathbb{Q}} \left[\lambda_q^{\mathrm{da}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}) + \lambda_q^{\mathrm{id,ch,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,ch}} - p_q^{\mathrm{b,id,ch}})\right]$$

$$/(|\mathbb{Q}| \cdot T^{\mathrm{q}}) - c^{\mathrm{cyc,id}}, \tag{6.57}$$

s.t. (6.15), (6.18)-(6.20), (6.25)-(6.26), (6.28)-(6.36), (6.56),

[4] Parameter $V_q^{\mathrm{id,ch}}$ is identical for the four consecutive 15 min of any hour.

$$\lambda_q^{\mathrm{da}} = \sum_{u \in \mathbb{U}_q^{\mathrm{da}}} Y_{q,u}^{\mathrm{sw,da}} \cdot B_{q,u}^{\mathrm{sw,da}}, \qquad \forall\, q \in \mathbb{Q}, \tag{6.58}$$

$$(p_q^{\mathrm{b,id,ch}} + p_q^{\mathrm{s,id,ch}}) \cdot T^{\mathrm{q}} \leq V_q^{\mathrm{id,ch}}, \qquad \forall\, q \in \mathbb{Q}, \tag{6.59}$$

$$p_q^{\mathrm{d,id}} - p_q^{\mathrm{c,id}} = p_q^{\mathrm{s,id,ch}} + p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,id,ch}} - p_q^{\mathrm{b,da}}, \quad \forall\, q \in \mathbb{Q}. \tag{6.60}$$

In order to use them in the RT stage, also here the optimized values for $p_q^{\mathrm{b,id,ch}}$, $p_q^{\mathrm{s,id,ch}}$, $p_q^{\mathrm{c,id}}$, and $p_q^{\mathrm{d,id}}$ in problem VIII are derived and defined as parameters.

Real-time stage (problem IX)

In contrast to the DA market, in which the participation of additional storage capacity increases the market size, as a result of passive balancing actions arbitraging imbalance prices reduces the size of the RT market by reducing the NRV. The NRV thus limits the arbitrage potential. For profit maximizing players it may make sense not to seek this limit, but to use less capacity to arbitrage RT imbalance prices due to the price-effect.

Price-effect data for the RT balancing market is not readily available. By using 15 min marginal activation price data for (1) increasing amounts of reserve capacity and (2) different reserve products, from the Belgian TSO Elia [100], we construct piecewise linear RT market resilience functions. Since the Belgian RT balancing market applies marginal single-pricing, we assume the marginal activation prices to reflect both long and short RT imbalance prices.[5] This data is available for different scenarios for every 15 min market period. The resilience functions developed here consist of data for the activation of down and upward contracted secondary control (which typically includes about 140 MW times T^{q}), and of data for down and upward reserve volumes of 300 MW times T^{q}, 600 MW times T^{q}, and the maximum available amount of reserve capacity times T^{q}. Since pro rata activation applies to contracted secondary control in Belgium, the marginal activation price for the entire volume of down and upward contracted secondary control is assumed to be constant at its marginal activation price, independent from what share of its total volume is activated.[6] Without participation of the additional storage capacity, the system is characterized by a certain imbalance price and accompanying NRV (i.e., the MRP) for each 15 min

[5] It is acceptable to ignore the balance-incentivizing component, since in Belgium it only applies to BRP imbalances in the same direction as the SI, not to passive balancing actions.

[6] In addition, in (the theoretical) case no reserve capacity is activated, the long imbalance price is assumed to equal the upward reserve price, while the short imbalance price corresponds to the downward reserve price.

settlement period. This MRP serves as reference point from which the storage operator can deduce its price-effect (Fig. 6.4b).

Similar to the DA market, we relax the price-taking assumption by considering the piecewise linear RT market resilience functions, illustrating the degree to which additional BRP imbalances would affect the imbalance price. Again, we approximate the piecewise linear functions by stepwise functions to solve MILPs instead of nonconvex MIQPs to approximate the piecewise linear outcome. Objective function (6.37) is updated to (6.61), given the transactions in the previously held DA market (6.18) and ID market (6.38), and the DA price (6.58), subject to additional constraints (6.62)-(6.65), and still subject to (6.39)-(6.49):

$$\pi^{\mathrm{op,rt}} = \max \sum_{q \in \mathbb{Q}} \Big[\lambda_q^{\mathrm{da}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,da}} - p_q^{\mathrm{b,da}}) + \lambda_q^{\mathrm{id,ch,o}} \cdot T^{\mathrm{q}} \cdot (p_q^{\mathrm{s,id,ch}} - p_q^{\mathrm{b,id,ch}})$$

$$+ \sum_{u \in \mathbb{U}_q^{\mathrm{rt}}} (Y_{q,u}^{\mathrm{sw,rt,+}} \cdot T^{\mathrm{q}} \cdot p_{q,u}^{\mathrm{i,+}} - Y_{q,u}^{\mathrm{sw,rt,-}} \cdot T^{\mathrm{q}} \cdot p_{q,u}^{\mathrm{i,-}})\Big]$$

$$/(|\mathbb{Q}| \cdot T^{\mathrm{q}}) - c^{\mathrm{cyc,rt}}, \tag{6.61}$$

s.t. (6.15), (6.18), (6.36), (6.38)-(6.50), (6.56), (6.58),

$$\sum_{u \in \mathbb{U}_q^{\mathrm{rt}}} p_{q,u}^{\mathrm{i,+}} = p_q^{\mathrm{i,+}}, \qquad \forall\, q \in \mathbb{Q}, \tag{6.62}$$

$$\sum_{u \in \mathbb{U}_q^{\mathrm{rt}}} p_{q,u}^{\mathrm{i,-}} = p_q^{\mathrm{i,-}}, \qquad \forall\, q \in \mathbb{Q}, \tag{6.63}$$

$$b_{q,u}^{\mathrm{sw,rt}} \cdot (X_{q,u}^{\mathrm{sw,lo,rt}} + R_q^{\mathrm{nrv}}) \leq T^{\mathrm{q}} \cdot (p_{q,u}^{\mathrm{i,+}} - p_{q,u}^{\mathrm{i,-}})$$

$$\leq b_{q,u}^{\mathrm{sw,rt}} \cdot (X_{q,u}^{\mathrm{sw,up,rt}} + R_q^{\mathrm{nrv}}), \qquad \forall\, q \in \mathbb{Q}, u \in \mathbb{U}_q^{\mathrm{rt}}, \tag{6.64}$$

$$\sum_{u \in \mathbb{U}_q^{\mathrm{rt}}} b_{q,u}^{\mathrm{sw,rt}} = 1, \qquad \forall\, q \in \mathbb{Q}, \tag{6.65}$$

$$p_{q,u}^{\mathrm{i,+}}, p_{q,u}^{\mathrm{i,-}} \in \mathbb{R}_+\,, \; b_{q,u}^{\mathrm{sw,rt}} \in \{0,1\}\,,$$

$$\mathbb{U}_q^{\mathrm{rt}} = \{1, 2, ..., \sum_{k \in \mathbb{K}^{\mathrm{rt}} \setminus \{|\mathbb{K}^{\mathrm{rt}}|\}} N_{q,k}^{\mathrm{sw,rt}}\}, \qquad \forall\, q \in \mathbb{Q}, u \in \mathbb{U}_q^{\mathrm{rt}}. \tag{6.66}$$

6.4 Results

6.4.1 Data

The price data for the DA and ID markets originates from the Belgian power exchange BELPEX [169], German and French power exchange EPEX SPOT [171], and Dutch power exchange APX [170]. RT imbalance price data is obtained from the Belgian TSO Elia [100], French TSO RTE [180], German TSO Amprion [243], and Dutch TSO TenneT [188]. Finally, Belgian price-effect data from BELPEX is used for the DA market, as well as for ID trading volume data, and both NRV and marginal reserve activation price data is retrieved from Elia to construct RT market resilience functions.

Fig. 6.6a provides information on the average market resilience function slope for the DA market for both additional supply and demand, while Fig. 6.6c gives this information for the RT market for both down and upward reserve activation, and Fig. 6.6b shows the trading volume for the continuous hourly ID market, all for the Belgian market zone for 2014. In these duration curves, the x-axis refers to the share of 15 min periods of the total of 35 040 15 min periods.

Unless specified otherwise, the used storage plant characteristics, along with other input data, are displayed in Table 6.1, and serve to model typical PHS plants. Even though we sometimes refer to other power rating sizes, we assume a fixed discharge duration of 4 h throughout this chapter.

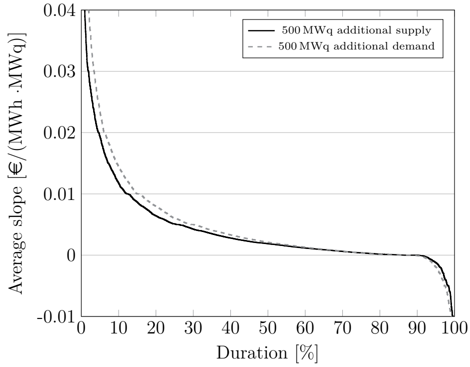
Table 6.1: Input parameters.

$C^{\text{inv,e}}$	50	€/kWh	N^{cyc}	100 000	-	$P^{\text{d,min}}$	0	MW	$R^{\text{d,do}}$	50	%/min
$E^{\max}$	2000	MWh	$P^{\text{c,max}}$	500	MW	$P^{\text{i,max}}$	1000	MW	$R^{\text{d,up}}$	50	%/min
$E^{\min}$	0	MWh	$P^{\text{c,min}}$	0	MW	$R^{\text{c,do}}$	50	%/min	η^{c}	86.6 %	
N^{cal}	50	a	$P^{\text{d,max}}$	500	MW	$R^{\text{c,up}}$	50	%/min	η^{d}	86.6 %	
$\lvert\mathbb{K}^{\text{da}}\rvert$	7	-	$\lvert\mathbb{K}^{\text{rt}}\rvert$	10	-	$\lvert\mathbb{Q}\rvert$	192		$\lvert\mathbb{Q}^{\text{fq}}\rvert$	48	-
$S^{\text{tar,da}}$	1.0	€/MWh	$S^{\text{tar,rt}}$	1.0	€/MWh	T^{q}	0.25	h			

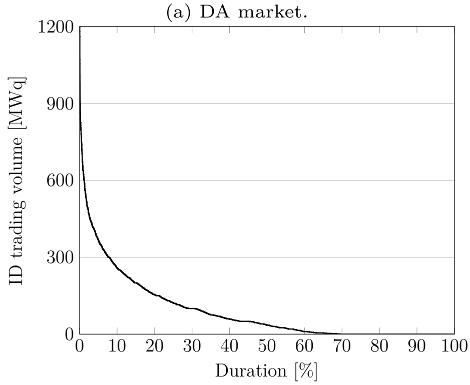
6.4.2 Arbitrage potential

No price-effect

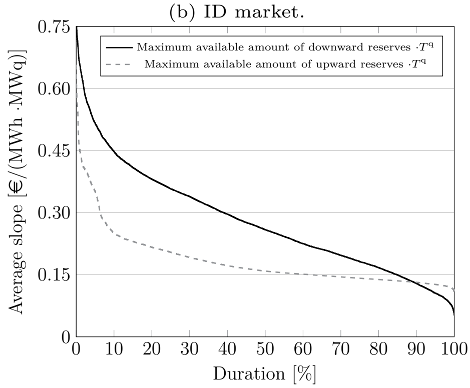
Fig. 6.7a shows the electricity storage arbitrage potential for the four market zones of the CWE region for 2014 under the assumption that the storage transactions do not affect the price. It illustrates the extent to which the different short-term and geographical markets on the one hand, and participation



(a) DA market.



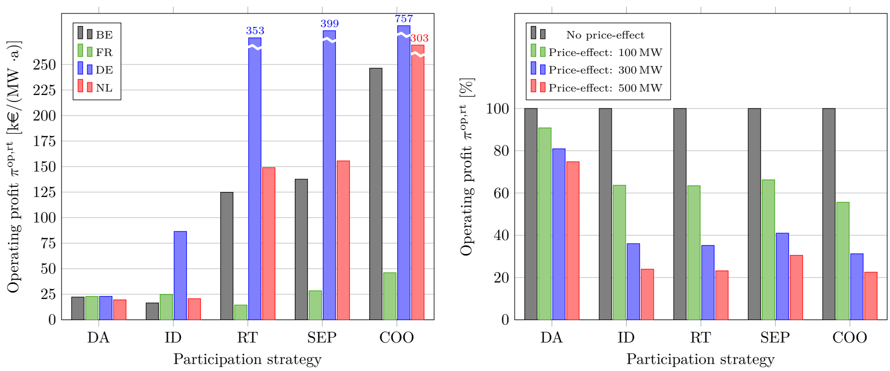
(b) ID market.



(c) RT market.

Figure 6.6: Fig. 6.6a shows the average DA market resilience function slope up to 500 MWq additional demand (upward slope) and supply (downward slope). Fig. 6.6c shows this data for the RT market up to the maximum available upward reserve capacity (upward slope) and downward reserve capacity (downward slope). Fig. 6.6b shows the trading volume in the continuous hourly ID market, Belgium, 2014.

strategies on the other hand, exhibit interesting characteristics.[7] We consider five participation strategies (Table 6.2). Strategy “DA” refers to only participating in the DA market, while strategies “ID” and “RT” have similar meanings for the ID market and settlement side of the RT balancing market, respectively. Strategy “SEP” refers to a separate participation in all three short-term markets, while “COO” corresponds to a coordinated participation in these markets.



(a) CWE region, no price-effect.

(b) Belgium, price-effect.

Figure 6.7: Electricity storage arbitrage potential, 2014. Fig. 6.7a focuses on the CWE region, and does not consider the price-effect of additional storage capacity. Fig. 6.7b focuses on Belgium, does consider the impact of the price-effect, and is expressed in values relative to the no price-effect values.

Table 6.2: Description of the five considered participation strategies.

Strategy	Description
DA	DA market participation only.
ID	ID market participation only.
RT	RT market participation only.
SEP	Separate participation in the DA, ID, and RT markets.
COO	Coordinated participation in the DA, ID, and RT markets.

Due to the full market-coupling and harmonization in the CWE region for the DA market, unsurprisingly the DA market arbitrage value is in the same order of magnitude across the four market zones.

For the ID strategy, the explanation is twofold. First, ID trading volume is higher in France and Germany than in Belgium and the Netherlands, with no trading volume in 30.41 % of the time in Belgium (Fig. 6.6b) and 12.83 % in

[7]It is not meant to provide an accurate prediction of the value that electricity storage operators will capture, as it assumes a perfect foresight of prices for the upcoming day.

the Netherlands, compared to only 1.10 % in France and four 15 min periods in Germany. This limits the transactions the operator can execute in the former two market zones, as with no trading volume in certain hours we assume the storage operator not to be able to trade either. Second, in Germany three ID markets are organized, allowing for three types of arbitrage (i.e., intertemporal, intermarket, and intertemporal intermarket arbitrage) in the ID strategy, while for Belgium, France, and the Netherlands only intertemporal arbitrage is possible.

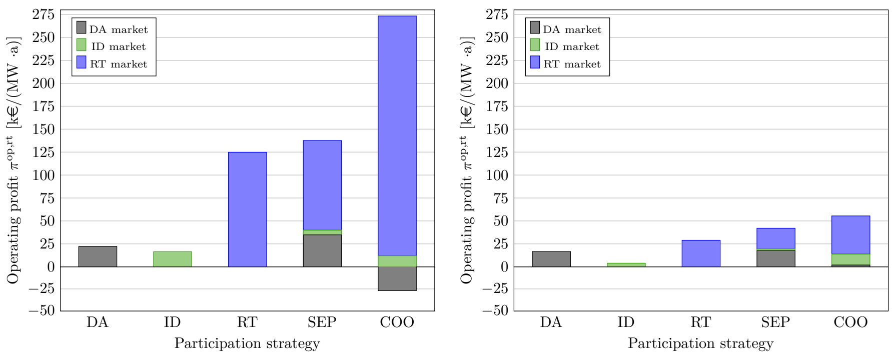
The significant difference between the RT market results for France compared to the other three market zones exists due to two main reasons. First, in France dual pricing applies, while in the other three market zones single-pricing is in place. Second, in France the RT market is based on 30 min time steps, compared to 15 min time steps in Belgium, the Netherlands, and Germany. The reason why a single-pricing design allows for a better valorization of the participation of flexible capacity is explained in Section 6.3.2. Furthermore, a finer temporal resolution would improve the extent to which the value of flexibility for the system is reflected and rewarded, because the resulting price signals would represent the physics of the system more accurately. Finally, the difference in arbitrage potential for the RT strategy between Belgium and the Netherlands on the one hand, and Germany on the other hand, can be attributed to the difference in price profiles and within-day price volatility.

When considering all three short-term markets in one arbitrage strategy, a significant difference between separate and coordinated participation is observed. The bulk of the value in these cases is driven by the RT market (Fig. 6.8a). In contrast to the SEP strategy, with COO, the storage operator can already anticipate large (favorable) imbalance positions by a priori creating a position in the opposite direction by means of DA and ID market trading. Fig. 6.8a illustrates that taking such positions can even lead to negative operating profits in the markets where this anticipatory behavior takes place, but that this loss is more than offset through higher revenues in the RT market. In contrast, negative operating profits cannot occur in the SEP strategy, as the transactions in each market are optimized sequentially.

Fig. 6.9a provides additional clarification by displaying information on the imbalance positions for the strategies including the RT market. In the SEP case, the total yearly imbalance volume is 5 898 MWh/MW,[8] with no imbalance position in 36.07 % of the time, and a full imbalance (i.e., at 200 % of the rated power) in 6.13 % of the time. With coordinated participation, these numbers amount to 10 318 MWh/MW, 17.59 %, and 35.92 %, respectively. A "full imbalance position" refers to having a nominated position in one direction

[8]The total yearly imbalance volume is calculated as $\sum_{q=1}^{q=35\,040} |p_q^{\mathrm{i},+} - p_q^{\mathrm{i},-}| \cdot T^{\mathrm{q}}$, and is represented in Fig. 6.9 by the area between the duration curves and zero.

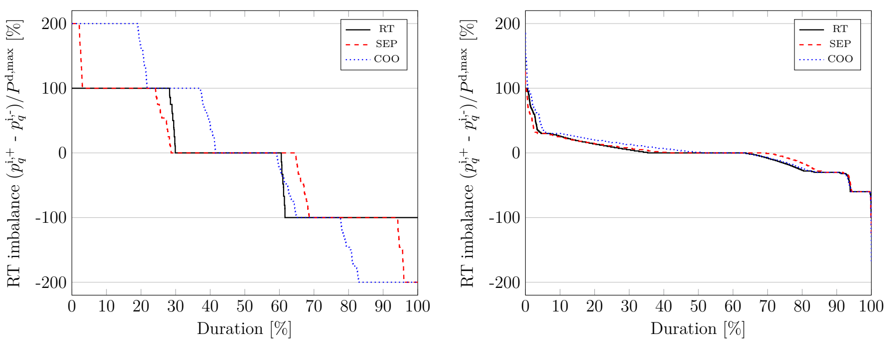
to the rated power (e.g., full charge power), while in RT the storage asset is operated in the opposite direction to the rated power (e.g., full discharge power). With strategy RT, the yearly imbalance volume amounts to 5 964 MWh/MW, with no imbalance in 30.66 % of the time, and no full imbalance positions as no anticipatory positions can be taken in the DA or ID market. Although the quantification of the risk associated with the different participation strategies is not in the scope of this chapter, it has to be noted that the coordinated participation is considered to be far more riskier. To approach the indicated value the operator has to have an accurate expectation of upcoming DA, ID, and RT prices already at the DA stage.



(a) No price-effect.

(b) Price effect: 500 MW.

Figure 6.8: Market-wise origin of the electricity storage arbitrage potential, Belgium, 2014.



(a) No price-effect.

(b) Price-effect: 500 MW.

Figure 6.9: Imbalance positions of the storage plant, expressed as percentage of the installed power rating, Belgium, 2014.

Price-effect

Fig. 6.7b displays the arbitrage potential when considering the price-effect, resulting from the participation of additional large-scale storage resources. This is done in values relative to the calculated operating profit when assuming to be a price-taker in the market with no price-effect (Fig. 6.7a). The displayed value per MW without price-effect for the DA market decreases rather slowly with the storage size when considering the price-effect. In contrast, due to the (current) relatively low ID market trading volume in Belgium (Fig. 6.6b), the value for the ID market decreases more quickly, as well as for the RT market, as the RT price-effect is many times stronger (Fig. 6.6c vs. Fig. 6.6a).

While the bulk of the value in the SEP and COO strategies is again provided by the RT market (Fig. 6.8b), this is to a much lesser extent. As the share of large imbalances decreases due to the emerged trade-off between the capacity used and the remaining price spread, negative anticipatory behavior in the DA and ID market occurs less frequently and less strongly, with no negative operating profit for the DA market anymore.

Fig. 6.9b shows that total yearly imbalance volumes decrease significantly due to the consideration of the price-effect, to prevent imbalance price spreads from disappearing or strongly decreasing. With the RT strategy, the yearly imbalance volume amounts to 1 514 MWh/MW, while for the SEP and COO strategies the imbalance volume amounts to 1 355 MWh/MW and 1 804 MWh/MW, respectively. Full imblances do not appear anymore in any of the participation strategies, and no imbalances occur in 28.50 %, 28.50 %, and 12.66 % of the time, for the RT, SEP, and COO strategies, respectively. Furthermore, 87.34 % of the imbalances are smaller than 50 % of the rated power for the RT strategy, while this is 89.04 % and 88.26 % for the SEP and COO strategies. The latter figures for the case when not considering the price-effect are only 1.97 %, 6.37 %, and 6.34 %, respectively. This illustrates that whereas transactions are always at full (remaining) power rating when not considering the price-effect, unless of course the energy buffer constrains this full-power-operation, here the transactions are more heavily constrained due to the price-effect.

Finally, we observe three things based on Table 6.3. First, the number of time steps including imbalance positions increase when considering the price-effect. This shifting of imbalances to neighboring market periods is done to keep the price spread from reducing as much as possible. Second, (surprisingly) the majority of the storage plant's imbalances do not seem to affect the price, as the imbalance positions are chosen such that the NRV remains on the flat parts of the RT resilience function (Fig. 6.4b). This allows for arbitrage without reduction of the price spread, and (in part) explains the previous observation.

While flat segments may occur at different places in the RT market resilience curves, they can mainly be attributed to the pro rata activation of contracted secondary control in the Belgian RT balancing market. In case the market design does not include such pro rata activation, these flat segments are no longer present in the piecewise linear RT resilience functions, thereby always affecting the price when arbitraging at those segments. As such, we hypothesize that the arbitrage value in the RT market would decrease even more than the values displayed in Fig. 6.7b. When there is an impact on the price, the price-effect in the RT market is always "intuitive". Segments are considered to be intuitive if the price decreases with additional supply (i.e., a positive imbalance) and increases with additional demand (i.e., a negative imbalance). In contrast to the RT market resilience functions, counterintuitive segments are present in the DA market resilience functions. Ref. [9] explains that this is the result of differences in accepted block orders.[9] Third, passive balancing can serve a valuable social purpose. The lion's share of the storage plant's imbalances are "good" imbalances, as they contribute to a secure operation of the system by reducing the amount of reserves the TSO has to activate. The small share of "neutral" imbalances refer to situations in which an imbalance in the same direction as the SI is created, but in which the imbalance price remains unchanged (i.e., at a flat segment). The very minor share of "bad" imbalances refer to situations similar to neutral imbalances, but in which the imbalance price further increases in case NRV >0, and further decreases in case NRV <0. Whereas, some regulators prefer a dual-pricing scheme (e.g., France), as this avoids BRPs to be incentivized to speculate on the direction of the SI, or do not contractually allow BRPs to deviate from their nominated position, even though that might help the system (e.g., Germany), we argue that incentivizing design changes should be considered for these balancing markets.

Table 6.3: RT imbalance and price-effect data, Belgium, 2014.

	Imbalance		Price-effect			Imbalance		
	Yes	No	Intuitive	None	Counter-intuitive	Good	Neutral	Bad
	[%]	[%]	[%]	[%]	[%]	[%]	[%]	[%]
RT (no price-effect)	69.34	30.66	-	-	-	97.06	2.94	-
RT (price-effect: 500 MW)	71.50	28.50	16.22	83.78	0.00	97.06	2.65	0.29
SEP (no price-effect)	63.93	36.07	-	-	-	91.85	8.15	-
SEP (price-effect: 500 MW)	71.50	28.50	16.89	83.11	0.00	86.14	10.66	3.20
COO (no price-effect)	82.41	17.59	-	-	-	88.22	11.78	-
COO (price-effect: 500 MW)	87.34	12.66	15.67	84.33	0.00	88.80	9.01	2.19

[9] Additional supply can cause supply (demand) block orders that are accepted (rejected) in the reference case to become rejected (accepted), while additional demand can cause demand (supply) block orders that are accepted (rejected) in the reference case to become rejected (accepted).

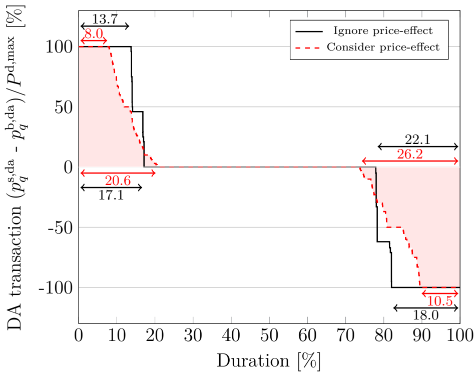
6.4.3 Market actions

Duration curves of the transactions in the Belgian DA, ID, and RT market, for 2014, are displayed in Fig. 6.10, for both a storage operator which is assumed to be a price-taker in the market and a storage operator that takes into account its price-effect. In the former case, the storage asset is always used to its full power rating, unless bounded by the limited energy storage capacity. In contrast, in the latter case, fewer full load hours are observed (DA: 18.5 % vs. 31.7 %, ID: 0.3 % vs. 21.7 %, RT: 0.6 % vs. 66.7 %) to keep price spreads from diminishing too much. Although (dis)charge actions are partially shifted to neighboring market periods, observed through the increased number of operational hours of the storage plant (DA: 46.8 % vs. 39.2 %, ID: 32.4 % vs. 26.4 %, RT: 71.5 % vs. 69.3 %), in total less energy is bought (DA: 1501 MWh/MW vs. 1790 MWh/MW, ID: 322 MWh/MW vs. 1208 MWh/MW, RT: 865 MWh/MW vs. 3408 MWh/MW) and sold (DA: 1126 MWh/MW vs. 1343 MWh/MW, ID: 242 MWh/MW vs. 906 MWh/MW, RT: 649 MWh/MW vs. 2556 MWh/MW).[10]

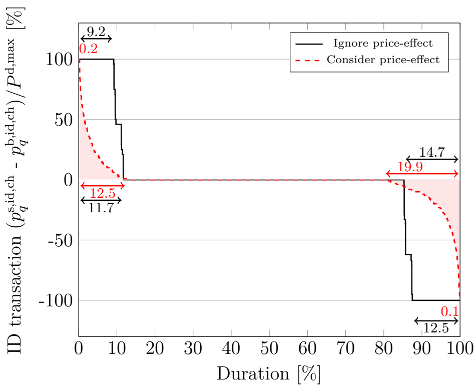
6.5 Conclusions

This chapter further informs the field of electricity storage valuation in short-term markets with two modeling-wise contributions. First, it presents PBUC model formulations that allow to aggregate multiple storage arbitrage opportunities in a single operation strategy. All three short-term markets, i.e., the DA, ID, and RT balancing market, are considered, as well as the opportunity to capture three types of price differences: (1) over time in each individual market (i.e., intertemporal arbitrage), (2) over the three markets for the same market period (i.e., intermarket arbitrage), and (3) over time over the three markets (i.e., intertemporal intermarket arbitrage). Second, the price-effect is studied with high detail for all three short-term markets: for the DA market by using piecewise linear DA market resilience functions, for the ID market by using trading volume data, and for the RT balancing market by using piecewise linear RT market resilience functions. While the first two are published by the power exchange, the latter are developed in this chapter based on marginal reserve activation prices published by the TSO.

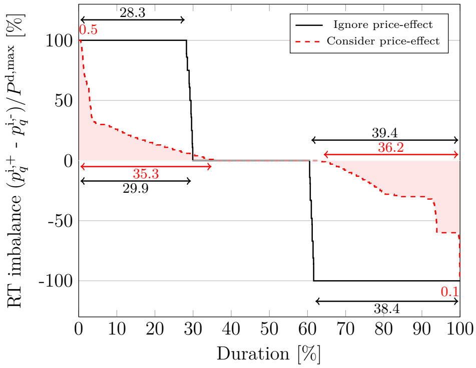
[10] The total yearly volumes are calculated similarly to the imbalance volumes in Fig. 6.9. The buy volumes are represented by the area between the negative part of the duration curves and zero, while the sell volumes are represented by the area between the positive part of the duration curves and zero.



(a) Participation strategy: DA.



(b) Participation strategy: ID.



(c) Participation strategy: RT.

Figure 6.10: Considering the price-effect leads to fewer full load hours, more operational hours, and less energy traded in total. The illustrated transactions when considering the price-effect are those of the 500 MW storage plant. The DA and ID transactions, and RT imbalances, are expressed as percentages of the rated power, Belgium, 2014.

We show the extent to which the three short-term markets, and their combination, in the four market zones of the CWE region are potentially interesting for electricity storage arbitrage. This is intended to support market participants in storage investment and operation decisions, and to inform policy-makers about the impact of market design rules on the storage arbitrage potential. While the arbitrage potential for the DA markets, which are coupled and harmonized, is quite similar in the Belgian, French, German, and Dutch market zones, this is not entirely the case for the ID markets, which are only partly coupled and harmonized, and not at all for the RT balancing markets, which are largely noncoupled and nonharmonized. Aggregating the arbitrage opportunities for the three short-term markets increases the storage value, with the aggregation strategy, i.e., separate or coordinated participation, determining the expected additional complexity and risk. The price-effect is much stronger in the ID and RT balancing market compared to the DA market, with the average arbitrage value per unit of power decreasing to a larger extent with the storage size in the ID and RT markets. For all short-term markets, considering the price-effect leads to three observed changes in the storage operation and trading behavior: fewer full load hours, more operational hours, and less traded energy.

In the bigger picture of applications for which storage systems can be used, one could wonder how relevant arbitrage opportunities in the short-term markets are for the business case compared to longer-term contracts for, e.g., frequency control. However, Chapter 4 shows that reserve contract durations are becoming shorter as well, through which stable longer-term revenue streams for storage are becoming rather uncommon. An exception to this trend towards shorter-term contracts is the uprise of capacity markets. However, these do not value flexibility but firm capacity, and usually represent complementary revenue streams next to participation in the short-term markets.

Chapter 7

Multi-player operation

Auction-based allocation of shared electricity storage resources through physical storage rights

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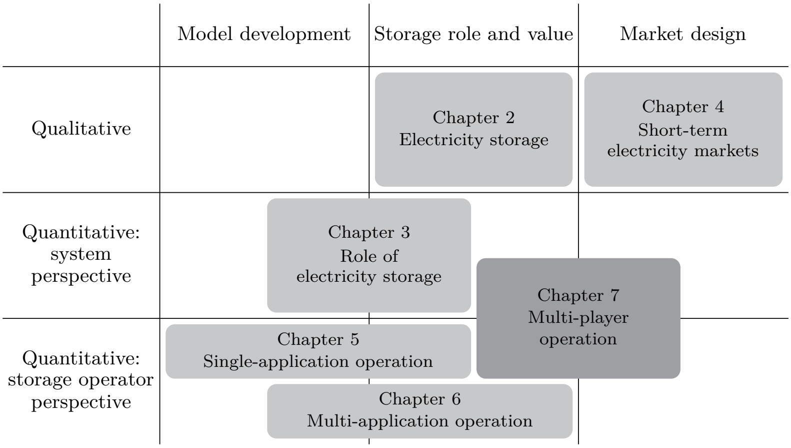
The first author is the main author of this article. The contributions of the first author include the literature study, the co-development of the models, the software implementation in MATLAB and GAMS, the analysis and interpretation of the results, and the writing of the manuscript. Support and supervision in the development of the models, and the analysis and interpretation of the results, are provided by the second, third, and fourth author. A preliminary version of this article is published as a DIW Berlin Discussion Paper [231].

Abstract:

This chapter proposes a new electricity storage business model based on multiple simultaneously considered revenue streams, which can be attributed to different market activities and players. These players thus share electricity storage resources and compete to obtain the right to use them in a dynamic allocation mechanism. It is based on the design of a new periodically organized auction to allocate shared storage resources through physical storage rights between different market players and accompanying applications. Through such a

flexibility platform owners of flexible resources can commercialize their flexible capacity over different applications, while market players looking for additional flexibility can obtain this through a pay-per-use principle and thus not having to make long-term investment commitments. As such, they can quickly adapt their portfolio according to the market situation. Alternatively, through such an allocation mechanism players can effectively share storage resources. Players may be incentivized to participate as they can share the investment cost, mitigate risk, exploit economies of scale, overcome regulatory barriers, and merge time-varying and player-dependent flexibility needs. The mechanism allocates the limited storage resources to the most valuable application for each market-clearing, based on the competing players' willingness-to-pay. An illustrative case study is provided in which three players share storage resources that are allocated through a daily auction with hourly market-clearings.

Positioning:



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7.1 Introduction

The integration of variable RES is a major challenge for the operation of the power system. Their limited controllability and predictability results in an increased need for power system flexibility, while flexible conventional power plants currently experience decreasing profitability as a result of low electricity prices and a limited number of operating hours [103]. Flexibility is the ability to provide up and downward power adjustments to deal with temporary imbalances between generation and consumption of electric energy [190, 244]. This flexibility can be provided by flexible generation and consumption, and electricity storage, but can also be activated in neighboring regions through interconnection capacity and the further integration of adjacent markets (Fig. 7.1). Electricity storage has the ability to compensate temporary power surpluses and shortages by decoupling the generation of electric energy from its consumption over time. The extent of this compensation is limited by its storage capacity.

Although there is a need for flexibility because of its increasing demand and decreasing supply, market participants are only incentivized to integrate new flexible resources if the investment is profitable. In addition, the value of storage is often underestimated due to the focus on operation strategies based on only a single application, usually price arbitrage between off-peak and on-peak hours. However, determining the true value of electricity storage will likely require the aggregation of multiple applications while accounting for the interdependence between potential revenue streams [32, 33, 34]. The value of individual applications cannot simply be added together, but need to be co-optimized since different storage services can conflict with each other [192].

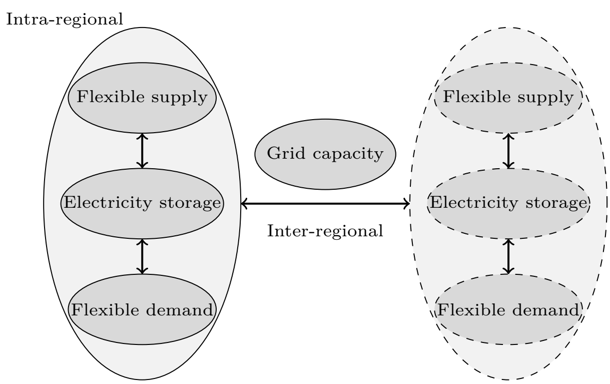


Figure 7.1: Overview of power system flexibility sources.

Therefore, this chapter considers a new storage business model based on multiple simultaneously considered revenue streams, which can be attributed to different activities in the market and can thus be the focus of different market players. As such, these market players share electricity storage resources and compete to use the shared storage resources. The allocation is based on the design of a periodically organized auction with sequential market-clearings, in which the right to use storage resources is traded between different players.

7.1.1 Electricity storage applications

Electricity storage refers to systems, bidirectionally coupled with the power system, which buffer energy. This includes both systems in which the charging and discharging side is physically located at one location, e.g., PHS plants and BES systems, or at multiple locations, i.e., P2G systems in combination with a gas turbine. This definition distinguishes electricity storage from the broader concept of energy storage, which may, e.g., also include stock-piling fuel at the supply side of the power system.[1]

Historically, electricity storage plants were considered as an alternative for investing in peak-load generation, by charging during off-peak and discharging during on-peak moments. However, due to the liberalization of electricity markets and the integration of RES, distinct valorization paths for different applications of storage emerged [10, 25, 26, 27]. These can be categorized in energy, network, and reliability services.

Energy services include arbitrage and portfolio management of market participants. Arbitrage is based on price differences over time: electricity is bought and stored when the price is low, and is sold and generated again when the price is higher. Portfolio management is performed at different time scales, i.e., investment, scheduling, and operation, and covers generation investment deferral, inter-temporal energy shifting, and capacity firming, respectively. Through inter-temporal energy shifting generators optimize the value of generation by decoupling generation and physical injection, while consumers optimize the cost of consumption by decoupling consumption and physical offtake. Capacity firming can indicate the ability to smoothen the generation or consumption output, resulting in less volatile power profiles, or to follow predetermined output schedules to reduce imbalance positions in RT. Network services include the provision of frequency control (i.e., primary, secondary, tertiary)[2], voltage

[1] Power plants may have significant fuel reserves, e.g., the natural gas grid with its storage capabilities for gas-fired power plants, coal piles at classic thermal power plants, and nuclear fuel at nuclear power plants.

[2] In the ENTSO-E synchronous zone operating reserves are categorized into FCR, FRR, both automatic (aFRR) and manual (mFRR), and RR.

support, congestion management, and black-start capabilities to the TSO. In the future, some of these will likely be provided to the DSO as well. Reliability services include the provision of reliability on both the local and system level.

This multitude of applications makes electricity storage plants an interesting asset for a wide range of market participants. However, operating a storage plant to provide just one or a few of these services might not always result in a positive business case: profitability may require the aggregation of multiple applications.

7.1.2 Motivation

Although some studies focus on the co-optimization of different storage applications (e.g., [33, 192, 230]), most existing work focuses on only a single application or allocates the available storage resources a priori when considering multiple applications, instead of applying a periodically performed optimization process. In addition, the sharing and operation of storage resources by different players has only been studied to a limited extent, except for [32]. As such, the contribution of the auction-based allocation described in this chapter is that it does not a priori define the applications or even the market player that the storage resources will serve at a certain moment in time. This can be accomplished by the development of a centralized platform where periodical auctions with sequential market-clearings take place to allocate the right to use (dis)charge power capacities and energy storage capacity. These auctions can serve both settings where (1) multiple players share common storage plants and (2) multiple suppliers of storage resources and prospective consumers meet to trade physical storage rights. Whereas the presented allocation mechanism allows to simultaneously include multiple resource suppliers and players competing for the right to use them, and to simultaneously consider their offers, the method discussed in [32] considers a sequential allocation to players which express their need for flexible resources at different time scales. In addition, the presented allocation mechanism auctions physical (dis)charge power rights and storage capacity rights, whereas the allocation in [32] is based on actual utilization profiles.

Market players can have multiple incentives to share, contract, or offer storage resources by means of a periodically organized auction. First, this may allow them to exploit economies of scale, i.e., increasing the plant size at a reduced cost per unit of power and energy. Second, they can share the investment cost and associated risk, especially when considering large-scale storage plants. Third, as flexibility needs vary throughout the year and even throughout the day, and across market players, they may have different (possibly complementary) storage utilization patterns, providing an incentive to share resources. Fourth, this may allow them to overcome regulatory barriers, here we identify two. First, although PHS is currently the most mature storage technology, rapidly decreasing costs and technological advancements are making BES systems increasingly competitive [3]. To overcome barriers for such small-scale storage resources to participate in the market, the development of a centralized platform allows owners of these resources to offer flexibility to market players that aggregate them. Second, regulatory barriers might prevent storage operators to provide certain services simultaneously. E.g., in the US storage plants can either provide market-based or regulated services (e.g., congestion management to avoid grid upgrades), but they are not allowed to combine both in a single business case [245]. An auction such as the one proposed in this chapter can overcome this regulatory barrier by allocating storage rights to different players to provide either market-based or regulated services.

From a system point of view, there may be additional reasons to share storage resources. First, as (large-scale) storage resources are usually limited due to geographical requirements, they should be allocated to the most valuable services at each point in time. Second, due to the introduced competition to use storage resources, strategic under or overusage [215] is likely to occur less frequently.

This decoupling of the ownership of storage resources with its physical operation has similar characteristics to the treatment of transmission capacity, as both have the ability to move power, the former in time while the latter in space. In European electricity markets cross-border transmission capacity is auctioned explicitly or implicitly [246, 247]. The former indicates that market players can obtain the right to use interconnector capacity, after which they can use these capacities to capture price differences in neighboring markets. In the latter, these capacities are not auctioned to market players but allocated to the power exchange to include in the market-clearing algorithm to maximize social welfare. The allocation mechanism discussed in this chapter is based on explicit auctioning, as first the right to use storage resources is auctioned, after which players can use these resources in the electricity market. Furthermore, [248, 249] consider a situation where the surplus collected by the system operator or power exchange (i.e., storage congestion rent), following a central operation of storage resources to maximize social welfare, is allocated to players holding financial storage rights. These are based on the design of FTRs [250, 251], and thus remunerate storage investors by either the revenues of the auction of financial storage rights, or the value of the storage congestion rent itself. Similar to the proposed auction-based allocation mechanism, this allows them to recover the investment cost without participating in the electricity market themselves.

7.1.3 Contributions

The main contribution of this chapter is the presentation of an alternative approach for electricity storage plants to aggregate multiple applications. This is based on a new market for flexibility, namely a periodically organized auction to allocate shared storage resources through physical storage rights between different market players and accompanying applications. Through this allocation mechanism (1) market participants can share storage resources to exploit economies of scale, reduce the investment cost, mitigate risk, match complementary flexibility needs, and overcome regulatory barriers, and (2) owners of flexible resources can commercialize their flexible capacity over different applications while market players looking for additional flexibility have access to these resources on a short-term basis. As such, the latter do not have to make long-term investment commitments and can adapt their portfolio according to changing market situations.

The chapter is structured as follows. Section 7.2 discusses (Generalized) Nash games, mixed complementarity problems, and the designed storage allocation mechanism in more detail. Section 7.3 illustrates this auction-based allocation through a case study in which three market players share storage resources, by providing the mathematical formulation of the players' individual optimization problems and resulting market equilibrium problem. While Section 7.4 discusses the case study's results, Section 7.5 provides the conclusions of this chapter.

7.2 Methodology

7.2.1 (Generalized) Nash equilibrium problems

The interaction between several market players, in which each player aims to optimize the value of its objective function given the decisions by all rivals, can be mathematically formulated as an equilibrium problem. We first introduce Nash equilibrium problems (NEPs) [252] before discussing the concept of a GNEP [253]. Assume a market with a finite amount of players, in which each player $l \in \mathbb{L}$ faces the following optimization problem:

$$\max_{x_l} f_l(x_l, x_{\text{-}l}), \tag{7.1}$$

$$\text{s.t.} \quad x_l \in \mathbb{X}_l. \tag{7.2}$$

Each player's vector of decision variables x_l, has to be chosen from its set of feasible strategies $\mathbb{X}_l$, while the vector of decision variables of its rivals $x_{\text{-}l}$ is considered as given. A Nash equilibrium x_l^* is then reached when the following condition holds:

$$f_l(x_l^*, x_{\text{-}l}^*) \geq f_l(y_l, x_{\text{-}l}^*), \quad \forall\, l \in \mathbb{L}\,, y_l \in \mathbb{X}_l. \tag{7.3}$$

This equilibrium means that given the decisions by all rivals, no player has an incentive to deviate from its chosen strategy. An implicit assumption of the NEP is that the strategies chosen by the competing players only affect the players' objective function and not their feasible set of strategies. In contrast, in a GNEP this assumption is relaxed [253, 254, 255, 256, 257], as each player's vector of decision variables x_l has to be chosen from a set of feasible strategies $\mathbb{X}_l(x_{\text{-}l})$ that is affected by the strategies chosen by the competing players. A Generalized Nash equilibrium x_l^* is then reached when the following condition holds:

$$f_l(x_l^*, x_{\text{-}l}^*) \geq f_l(y_l, x_{\text{-}l}^*), \quad \forall\, l \in \mathbb{L}\,, y_l \in \mathbb{X}_l(x_{\text{-}l}^*). \tag{7.4}$$

The general structure of both an NEP and GNEP, consisting of a set of interrelated optimization problems, is illustrated in Fig. 7.2. In a GNEP, each player's objective function may be subject to both individual and shared constraints. While each individual optimization problem represents the decision process of one player, the equilibrium problem represents the interactions in a market environment of multiple interrelated players.

7.2.2 Mixed complementarity problems

The NEP and GNEP can be solved by formulating the problem as an MCP. This is done by deriving the first-order optimality, or KKT, conditions of each player's optimization problem and solving them simultaneously. In the MCP formulation, the complementarity conditions enforce that the inner product of an inequality constraint and the primal or dual variable[3] is zero, and the nonnegativity of both the inequality constraint and the primal or dual variable. This means that either the inequality constraint holds as an equality, i.e., is

[3] A constraint's dual variable represents the incremental improvement of the player's objective value when marginally relaxing the respective constraint, and can be interpreted as the marginal price of the resource subject to the constraint.

binding, or the primal or dual variable is zero. Mathematically, this is expressed by using the perpendicular operator $\perp$, which indicates complementarity.

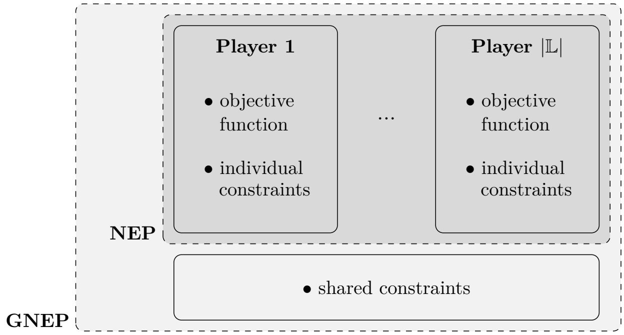


Figure 7.2: Illustration of (Generalized) Nash equilibrium problems.

An MCP is thus an array of equalities and inequalities which is obtained by aggregating all players' KKT conditions. However, when tackling a GNEP, aggregating the individual players' KKT conditions into an MCP results in a nonsquare system: the shared constraints are identical for each player, while the associated dual variables of each involved player may hold different values. This "squareness" issue can be solved by assigning an identical dual variable for each player to the shared constraint [253], meaning that each player values the shared resource identically, which leads to a single "price" for the shared resource [254, 255].

This approach can be interpreted as an auctioneer allocating the shared resource to the players according to the price they are willing to pay to obtain the right to use it. Their willingness-to-pay directly relates to the improvement of their objective value from a marginal relaxation of the shared resource.

7.2.3 Auction-based allocation of shared storage resources

The shared storage resources' allocation problem can be formulated as both an NEP and GNEP. In the former case, the suppliers of storage resources are modeled explicitly, while the consumers and suppliers in the market for storage resources interact by means of market-clearing conditions representing the auctioneer. This formulation relates to the situation where multiple suppliers and consumers of storage resources compete in a centralized market. In the latter case, the suppliers are not modeled explicitly but are included implicitly through the storage resources' shared constraints. Through these shared constraints an auctioneer is assumed to allocate the storage rights over the different players.

This formulation is particularly useful to represent the situation where multiple market players share the storage resources and allocate them periodically among each other.

It is well known from [253] that an NEP where the auctioneer is modeled explicitly yields the same solution as a GNEP where the dual variables of each player for the shared constraints are assumed to be identical. If the solution is nonunique, the two solutions may differ in terms of the primal variables (i.e., operating decisions), but the objective value (i.e., pay-off) for each player must be identical. In this chapter, we use the GNEP formulation in a case study in Section 7.3 as it illustrates a case in which three players share storage resources. For illustrative purposes, the remainder of the discussion assumes a single storage plant.

In both formulations the auctioneer thus acts as a facilitator between the supply of shared storage resources (i.e., charge power $P^{\mathrm{c,max}}$, discharge power $P^{\mathrm{d,max}}$, energy storage capacity E^{max}) and a number of players $|\mathbb{L}|$ which compete to obtain the right to use them. A periodical auction is organized, in which for each market period $t \in \mathbb{T}$ the supplier of the storage resources submits supply bids s^{c}_t, s^{d}_t, s^{e}_t and each market player $l \in \mathbb{L}$ has the opportunity to submit demand bids $d^{\mathrm{c}}_{l,t}$, $d^{\mathrm{d}}_{l,t}$, $d^{\mathrm{e}}_{l,t}$ for each storage resource (Fig. 7.3, left). The supplier is assumed to provide a supply bid for each shared resource equal to its maximum capacity, to be sold at any price defined by the market. Each player l bids the maximum price he is willing to pay to obtain the right to use a specified volume of each storage resource. This maximum price equals its incremental pay-off. The auctioneer then aggregates the demand bids for each storage resource, i.e., the demand curve, and matches them with each resource's supply bid, i.e., the supply curve, which results in a market-clearing for each time step t (Fig. 7.3, right). This yields a cleared volume for the charge power rights $p^{\mathrm{c,max}}_{l,t}$, discharge power rights $p^{\mathrm{d,max}}_{l,t}$, and storage capacity rights $e^{\mathrm{max}}_{l,t}$ for each player l, and uniform market-clearing prices μ^{c}_t, μ^{d}_t, μ^{e}_t. In equilibrium, these prices equal the marginal willingness-to-pay for each respective resource.

Similar to the case in current electricity markets, the allocation process may be iterated at different timeframes (e.g., week-ahead, DA, ID, RT) to allow players to adjust their obtained physical storage rights, based on updated market information. In a first auction (e.g., DA) the shared resources are allocated to the different players according to their willingness-to-pay, which is dependent on their market expectations and risk aversion, while in a consecutive allocation closer to RT (e.g., ID) players can trade and reallocate the obtained resources among each other: players that contracted too much can offer part of their obtained rights again to the platform, while players that contracted too little can bid to obtain additional storage rights. As is the case in electricity markets, these sequential markets for storage resources may also allow for arbitrage opportunities as price spreads can be captured over the different sequential markets. Arbitrageurs could, e.g., obtain additional storage rights at the DA stage to afterwards sell in the ID market to other players if they expect the ID price to clear at a higher price. Alternatively, players could, e.g., postpone the reservation of physical storage rights in the DA market to the ID market if they expect the ID market to clear at a lower price. Although the value of this arbitrage is related to the presence of price spreads, it also depends on the effect of additional/fewer requested storage rights on prices, as arbitrage may reduce price spreads by increasing low prices when requesting additional storage rights and decreasing high prices when requesting fewer storage rights.

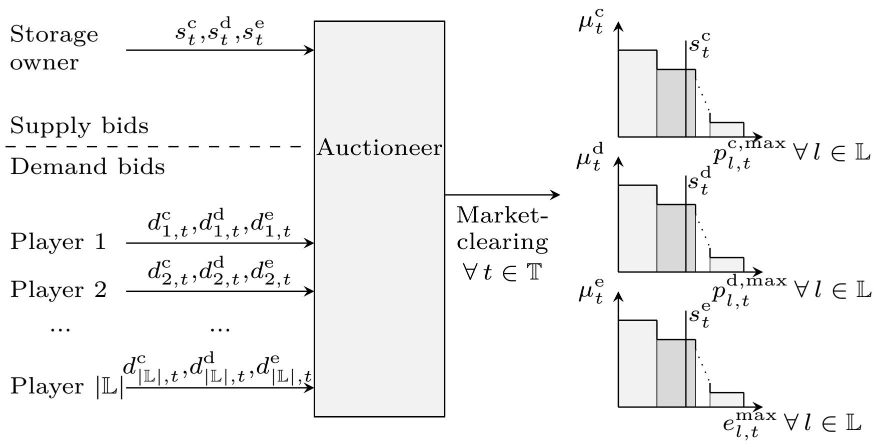


Figure 7.3: Market-clearing mechanism to allocate storage resources.

7.3 Case study

To illustrate the presented auction-based allocation mechanism, a case study is shown for a daily auction with hourly market-clearings in which three market players compete for constrained storage resources, i.e., $\mathbb{L} = \{a, p, r\}$, with index a representing a player arbitraging DA market prices, index p a player focusing on portfolio management, and index r a player that aims to use storage resources to capture imbalance price differences in the RT market. First, the individual optimization problems are presented as if electricity storage resources would be readily available to them. Second, we discuss which changes have to take place in order for the players to share storage resources and compete in an auction-based allocation mechanism, i.e., equilibrium problem. Third, the MCP formulation of the equilibrium problem is discussed while it is provided in full in Appendix A.

The model formulations of the provided case study include discretized hourly time periods $h \in \mathbb{H}$, with $|\mathbb{H}| = 24$ and T^{h} representing the length of one time period, i.e., one hour. Variables in parentheses denote the dual variables of the respective constraints. In addition, all players are assumed to be price-takers with perfect foresight for the next optimization horizon, i.e., the next day in this case study. The storage plant is assumed to have sufficiently fast ramp rates for the considered hourly time resolution, with no restrictions regarding simultaneous charge and discharge actions, and a sufficiently large cycle-life such that its impact on the operation is negligible. These storage plant assumptions might serve to model typical PHS plants.

7.3.1 Individual optimization problems

First, a storage operator is considered that aims to capture price differences in the DA market. This player is indicated by index a, and its optimization problem, in which the pay-off is maximized over a time horizon $|\mathbb{H}| \cdot T^{\mathrm{h}}$, reads as follows:

$$\max_{e_{a,h}, p^{\mathrm{c}}_{a,h}, p^{\mathrm{d}}_{a,h}} \sum_{h \in \mathbb{H}} \lambda^{\mathrm{da,o}}_h \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_{a,h} - p^{\mathrm{c}}_{a,h})\right] / (|\mathbb{H}| \cdot T^{\mathrm{h}}), \tag{7.5}$$

$$e_{a,h} = e_{a,h\text{-}1} + T^{\mathrm{h}} \cdot (p^{\mathrm{c}}_{a,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{a,h}/\eta^{\mathrm{d}}), \quad (\gamma^{\mathrm{e}}_{a,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.6}$$

$$p^{\mathrm{c}}_{a,h} \leq P^{\mathrm{c,max}}, \quad (\mu^{\mathrm{c}}_{a,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.7}$$

$$p^{\mathrm{d}}_{a,h} \leq P^{\mathrm{d,max}}, \quad (\mu^{\mathrm{d}}_{a,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.8}$$

$$e_{a,h} \leq E^{\mathrm{max}}, \quad (\mu^{\mathrm{e}}_{a,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.9}$$

$$e_{a,h}, p^{\mathrm{c}}_{a,h}, p^{\mathrm{d}}_{a,h} \in \mathbb{R}_+ \,, \mathbb{H} \subset \mathbb{N}, \quad \forall\, h \in \mathbb{H}, \tag{7.10}$$

with $p^{\mathrm{c}}_{a,h}$ the charge power, $p^{\mathrm{d}}_{a,h}$ the discharge power, $e_{a,h}$ the stored energy, $\lambda^{\mathrm{da,o}}_h$ the DA market price, η^{c} the charge efficiency, and η^{d} the discharge efficiency. Constraint (7.6) expresses the intertemporal character of electricity storage, while (7.7)-(7.9) represent capacity bounds on the electricity storage resources.

Next, a RES generator operating a portfolio of both wind and PV capacity is considered. This player uses storage resources to increase the market value of its RES generation. This can be done by either directly selling its RES power output to the market or temporarily storing it during low price periods. This application of electricity storage results from the fact that periods experiencing high RES generation often coincide with lower price periods [103]. This player is indicated by index p, and its optimization problem is:

$$\max_{\substack{e_{p,h},p^{\mathrm{c}}_{p,h},p^{\mathrm{d}}_{p,h},\\ p^{\mathrm{g}}_{p,h},p^{\mathrm{l}}_{p,h}}} \sum_{h\in\mathbb{H}} \lambda^{\mathrm{da,o}}_{h} \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{g}}_{p,h} + p^{\mathrm{d}}_{p,h})\right]/(|\mathbb{H}| \cdot T^{\mathrm{h}}), \tag{7.11}$$

$$p^{\mathrm{c}}_{p,h} + p^{\mathrm{g}}_{p,h} + p^{\mathrm{l}}_{p,h} = A^{\mathrm{res,abs}}_{p,h}, \qquad (\gamma^{\mathrm{g}}_{p,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.12}$$

$$e_{p,h} = e_{p,h\text{-}1} + T^{\mathrm{h}} \cdot (p^{\mathrm{c}}_{p,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{p,h}/\eta^{\mathrm{d}}), \quad (\gamma^{\mathrm{e}}_{p,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.13}$$

$$p^{\mathrm{c}}_{p,h} \leq P^{\mathrm{c,max}}, \qquad (\mu^{\mathrm{c}}_{p,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.14}$$

$$p^{\mathrm{d}}_{p,h} \leq P^{\mathrm{d,max}}, \qquad (\mu^{\mathrm{d}}_{p,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.15}$$

$$e_{p,h} \leq E^{\mathrm{max}}, \qquad (\mu^{\mathrm{e}}_{p,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.16}$$

$$e_{p,h}, p^{\mathrm{c}}_{p,h}, p^{\mathrm{d}}_{p,h}, p^{\mathrm{g}}_{p,h}, p^{\mathrm{l}}_{p,h} \in \mathbb{R}_{+}\,,\ \mathbb{H} \subset \mathbb{N}, \qquad \forall\, h \in \mathbb{H}, \tag{7.17}$$

with $A^{\mathrm{res,abs}}_{p,h}$ the available RES power output, $p^{\mathrm{g}}_{p,h}$ the RES output directly sold to the market, and $p^{\mathrm{l}}_{p,h}$ the curtailed RES output. Constraint (7.12) denotes that the RES power output can either be stored, sold, or curtailed.

Unforeseen imbalances between generation and consumption are dealt with in RT on the balancing market, which is coordinated by the TSO. At the procurement side of the balancing market the TSO contracts and activates reserve capacity to cover SIs, while at the settlement side of the balancing market the TSO settles individual imbalance positions of market participants by means of an imbalance price that is based on the activation cost of reserves [103]. The third considered player is an arbitrageur that is active on the settlement side of the RT balancing market to capture imbalance price differences over time. As the RT balancing market is characterized by a small volume compared to the DA market, the imbalance positions this player can take while not diminishing the expected price spreads are assumed to be bounded by $P^{\mathrm{i,max}}_{r}$ (7.19). As such, the price-taking assumption assumed in this illustrative case study holds. Although the balancing market is usually characterized by quarter-hourly or half-hourly market periods, for illustrative purposes hourly market periods are assumed. This player is indicated by index r, and its optimization problem reads as follows:

$$\max_{e_{r,h}, p^{\mathrm{c}}_{r,h}, p^{\mathrm{d}}_{r,h}} \sum_{h \in \mathbb{H}} \lambda^{\mathrm{rt,o}}_{h} \cdot \left[T^{\mathrm{h}} \cdot (p^{\mathrm{d}}_{r,h} - p^{\mathrm{c}}_{r,h})\right] / (|\mathbb{H}| \cdot T^{\mathrm{h}}), \tag{7.18}$$

$$p^{\mathrm{c}}_{r,h} + p^{\mathrm{d}}_{r,h} \leq P^{\mathrm{i,max}}_{r}, \qquad (\gamma^{\mathrm{l}}_{r,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.19}$$

$$e_{r,h} = e_{r,h\text{-}1} + T^{\mathrm{h}} \cdot (p^{\mathrm{c}}_{r,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{r,h}/\eta^{\mathrm{d}}), \quad (\gamma^{\mathrm{e}}_{r,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.20}$$

$$p^{\mathrm{c}}_{r,h} \leq P^{\mathrm{c,max}}, \qquad (\mu^{\mathrm{c}}_{r,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.21}$$

$$p^{\mathrm{d}}_{r,h} \leq P^{\mathrm{d,max}}, \qquad (\mu^{\mathrm{d}}_{r,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.22}$$

$$e_{r,h} \leq E^{\mathrm{max}}, \qquad (\mu^{\mathrm{e}}_{r,h}), \quad \forall\, h \in \mathbb{H}, \tag{7.23}$$

$$e_{r,h}, p^{\mathrm{c}}_{r,h}, p^{\mathrm{d}}_{r,h} \in \mathbb{R}_{+}\,, \, \mathbb{H} \subset \mathbb{N}, \qquad \forall\, h \in \mathbb{H}, \tag{7.24}$$

with $\lambda^{\mathrm{rt,o}}_{h}$ the RT imbalance price.[4]

7.3.2 Generalized Nash equilibrium problem

When formulating the presented optimization problems as a GNEP, two changes take place. First, as they compete for the shared electricity storage resources, the constraints representing the limited charge power (7.7), (7.14), (7.21), discharge power (7.8), (7.15), (7.22), and energy storage capacity (7.9), (7.16), (7.23) are replaced by:

$$p^{\mathrm{c}}_{l,h} \leq p^{\mathrm{c,max}}_{l,h}, \quad (\tau^{\mathrm{c}}_{l,h}), \quad \forall\, l \in \mathbb{L}, h \in \mathbb{H}, \tag{7.25}$$

$$p^{\mathrm{d}}_{l,h} \leq p^{\mathrm{d,max}}_{l,h}, \quad (\tau^{\mathrm{d}}_{l,h}), \quad \forall\, l \in \mathbb{L}, h \in \mathbb{H}, \tag{7.26}$$

$$e_{l,h} \leq e^{\mathrm{max}}_{l,h}, \quad (\tau^{\mathrm{e}}_{l,h}), \quad \forall\, l \in \mathbb{L}, h \in \mathbb{H}, \tag{7.27}$$

with $p^{\mathrm{c,max}}_{l,h}$, $p^{\mathrm{d,max}}_{l,h}$, and $e^{\mathrm{max}}_{l,h}$ the allocated charge power rights, discharge power rights, and storage capacity rights, respectively. These physical rights are bounded by the supplied storage resources, which are assumed to equal the

[4] In Belgium the same imbalance price applies to positive and negative imbalances. While these prices may differ in case of large SIs because of the activation of a balance-incentivizing component, it is acceptable to ignore this component here: it only applies to imbalances in the same direction as the SI, which is not the case when arbitraging imbalance prices.

installed (dis)charge power rating and energy storage capacity in this illustrative case study:

$$\sum_{l \in \mathbb{L}} p_{l,h}^{\mathrm{c,max}} \leq P^{\mathrm{c,max}}, \quad (\mu_h^{\mathrm{c}}), \quad \forall\, h \in \mathbb{H}, \tag{7.28}$$

$$\sum_{l \in \mathbb{L}} p_{l,h}^{\mathrm{d,max}} \leq P^{\mathrm{d,max}}, \quad (\mu_h^{\mathrm{d}}), \quad \forall\, h \in \mathbb{H}, \tag{7.29}$$

$$\sum_{l \in \mathbb{L}} e_{l,h}^{\mathrm{max}} \leq E^{\mathrm{max}}, \qquad (\mu_h^{\mathrm{e}}), \quad \forall\, h \in \mathbb{H}. \tag{7.30}$$

Alternatively, when considering a centralized market for storage resources rather than a situation where players share them, the supply is characterized by index h as well as it will be time-varying. Second, a cost term is subtracted ex-post from each player's objective value, since the right to use the limited storage resources is now allocated through an auction instead of being readily available to them. The uniform prices of the shared resources μ_h^{c} (7.28), μ_h^{d} (7.29), μ_h^{e} (7.30) at each hourly market-clearing are determined by the willingness-to-pay of the players' marginally cleared demand bids to obtain the right to use them. The ex-post calculation of the profit π_l as opposed to the operating profit π_l^{op} is done by considering the objective value resulting from (7.5), (7.11), (7.18) and subtracting a cost term β_l:

$$\beta_l = \sum_{h \in \mathbb{H}} (p_{l,h}^{\mathrm{c,max}} \cdot \mu_h^{\mathrm{c}} + p_{l,h}^{\mathrm{d,max}} \cdot \mu_h^{\mathrm{d}} + e_{l,h}^{\mathrm{max}} \cdot \mu_h^{\mathrm{e}}), \quad \forall\, l \in \mathbb{L}, \tag{7.31}$$

$$\pi_l^{\mathrm{op}} - \beta_l = \pi_l, \qquad \forall\, l \in \mathbb{L}. \tag{7.32}$$

The MCP comprised of each player's KKT conditions and the shared constraints is solved in GAMS using the PATH solver [258], and is provided in Appendix A for both a daily auction with hourly market-clearings, and a less dynamic periodically organized (e.g., daily, weekly) auction including a single market-clearing, i.e., allocation, for each of the shared resources for the entire period (e.g., day, week). Since the considered optimization problems are convex and the players only face linear constraints, the KKT conditions are both necessary (i.e., an optimal solution satisfies the KKT conditions) and sufficient (i.e., each KKT point is an optimal solution) [257].

7.4 Results

The Belgian DA market price [169], RT imbalance price [100], and RES generation profiles [100] for 2014 are used for the illustrative case study. The hourly imbalance price $\lambda_h^{\mathrm{rt,o}}$ is calculated as the average of the four quarter-hourly imbalance prices in hour h. The RES portfolio of player p is assumed to consist of both PV systems and offshore wind turbines, both accounting for 50 % of the portfolio. The time-varying available RES power output $A_{p,h}^{\mathrm{res,abs}}$ is determined by multiplying the hourly availability of the respective sources by the installed capacity $A_p^{\mathrm{res,max}}$. The storage plant characteristics used for the case study, along with other input data, are displayed in Table 7.1.

Table 7.1: Input parameters.

E^{max}	200 MWh	$P_r^{\mathrm{i,max}}$	25 MW	$P^{\mathrm{d,max}}$	50 MW	η^{c}	86.6 %
$A_p^{\mathrm{res,max}}$	150 MW	$P^{\mathrm{c,max}}$	50 MW	T^{h}	1 h	η^{d}	86.6 %

Fig. 7.4 shows the individual operating profit π_l^{op} and total operating profit $\sum_{l\in\mathbb{L}} \pi_l^{\mathrm{op}}$ for 2014 as a result of the use of storage resources[5] for different allocations, either fixed a priori defined allocations (i.e., column 1 to 4) or allocations resulting from the proposed allocation mechanism (i.e., column 5 and 6). In columns one to three, π_l^{op} is shown for the case where the players are each allocated 100 % of the storage resources. Column four indicates π_l^{op} in case each player is awarded a fixed share equal to one-third of the storage resources for the entire year. Since the players are assumed to be price-takers in their respective markets (i.e., DA electricity and RT balancing market), one may expect that π_l^{op} is equal to one-third of π_l^{op} following a 100 % allocation to the respective player. Although this is the case for player a, this is not the case for player p (42.5 %) and player r (61.5 %) as their actions are limited by $A_{p,h}^{\mathrm{res,abs}}$ and $P_r^{\mathrm{i,max}}$ in the provided case study. Column five shows π_l^{op} when assuming a daily organized auction with a single market-clearing, i.e., daily allocated (dis)charge power and storage capacity rights, while column six is based on a daily organized auction with hourly market-clearings. Fig. 7.4 shows that the auction-based allocations lead to a higher total realized operating profit $\sum_{l\in\mathbb{L}} \pi_l^{\mathrm{op}}$, with shorter time frames for the market-clearings performing better. The latter ensures that the limited storage resources are allocated to the most valuable services at each point in time.

Table 7.2 shows π_l^{op}, β_l, and π_l for the different players. The revenue collected through the auctioning of the (dis)charge power and storage capacity rights is

[5] This means that for player p the value that would have been realized without use of the storage resources due to the RES generation is subtracted.

indicated by $\sum_{l \in \mathbb{L}} \beta_l$. The price of an auctioned right (i.e., μ_h^{c}, μ_h^{d}, μ_h^{e} for hourly allocations, and μ^{c}, μ^{d}, μ^{e} for single allocations per auction) only takes on a nonzero value when the inequality constraint representing the limited availability of the storage resource subject to the constraint is binding (i.e., (A.35)-(A.37) for hourly allocations, and (A.72)-(A.74) for single allocations per auction). In case the price is nonzero, it takes on the willingness-to-pay of the demand bid of the marginally cleared player for the respective resource. As such, the zero profit π_a and close-to-zero profit π_p indicate that when these players' bids to obtain storage rights are accepted, they represent the marginally cleared bids. This is similar to the situation in electricity markets, where the player of the marginally cleared demand bid pays as much as he values the consumption of electric power during that market period. Contrarily, the positive profit π_r shows that its bids to obtain storage rights not always represent the marginally cleared bid. This can be explained by the large price spreads in the RT market compared to the DA market, through which player r values the use of storage resources higher, and because the inequality constraints are not binding when he is the only player that contracts storage resources as its (dis)charge actions are limited by $P_r^{\mathrm{i,max}}$. In the former case player r pays the lower willingness-to-pay of one of the other cleared players, while in the latter case the price of the right of the storage resource subject to the constraint is zero. Contrary to this illustrative case study, as more players participate in such an auction, and more applications are considered, these situations occur less frequently. As such, the revenue collected through the auctioning of storage rights converges to the total captured value in the electricity market more closely.

Table 7.2: Yearly operating profit, cost to obtain storage rights, and profit, 2014.

	Daily auctions with hourly allocations			Daily auctions with daily allocations		
	Operating profit π_l^{op} [M€/a]	Cost β_l [M€/a]	Profit π_l [M€/a]	Operating profit π_l^{op} [M€/a]	Cost β_l [M€/a]	Profit π_l [M€/a]
Player a	0.445	0.445	0.000	0.365	0.365	0.000
Player p	0.369	0.336	0.033	0.230	0.197	0.033
Player r	1.934	0.367	1.567	1.958	0.584	1.374
$\sum_{l \in \mathbb{L}}$	2.748	1.148	1.600	2.553	1.146	1.407

Fig. 7.5 illustrates the allocation of the auctioned (dis)charge power and storage capacity rights for a daily auction with daily (Fig. 7.5a, Fig. 7.5c, Fig. 7.5e) and hourly (Fig. 7.5b, Fig. 7.5d, Fig. 7.5f) market-clearings for 2014. As for price-taking players with perfect foresight the overall daily value of storage resources is likely to be higher for arbitraging RT imbalance prices than arbitraging DA electricity prices, due to the larger and more frequent price spreads, player a and player p do not often get the opportunity to use more than 25 MW (i.e., $P_r^{\mathrm{i,max}}$) in the daily allocation case. However, for some hours of the day they might

actually have a higher willingness-to-pay and thus the storage resources would be valorized at a higher value. Therefore, when using more frequent market-clearings (i.e., with shorter durations), the storage resources are allocated more efficiently to the time-varying most valuable services, resulting in a higher total storage value.

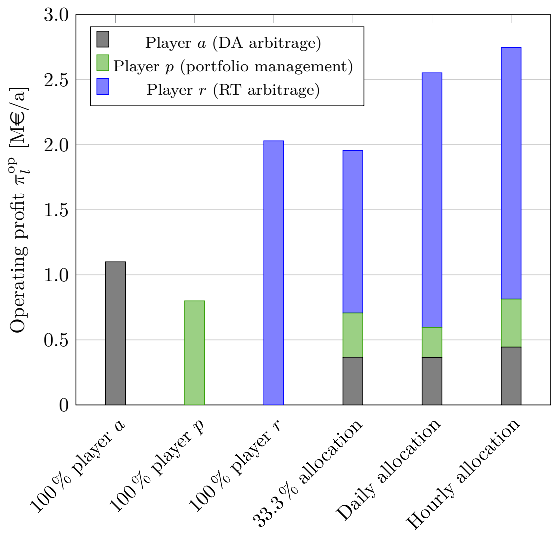
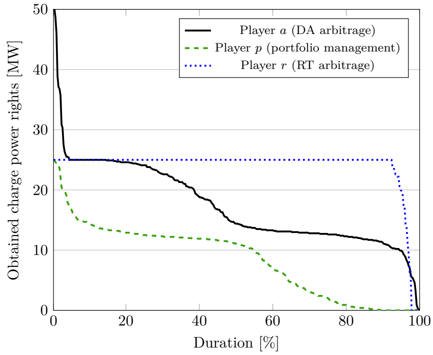


Figure 7.4: Total and individual operating profit for different allocations of the shared storage resources, 2014.

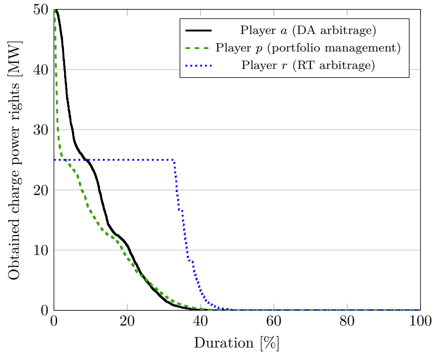
7.5 Conclusions

Electricity storage has the ability to compensate for temporary power surpluses and shortages by decoupling the generation of electric energy from its consumption over time, thereby meeting increased flexibility needs. However, market participants are only incentivized to invest in new flexible resources when the investment is profitable. As this may not be the case when only considering a single or a few storage services, maximizing the value of electricity storage requires the aggregation of multiple value streams in a single operating strategy.

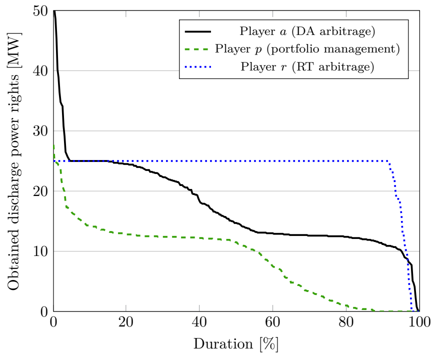
As such, this chapter proposes a new storage business model based on multiple simultaneously considered revenue streams, in which the applications or even the player that the storage resources will serve at a certain moment in time are



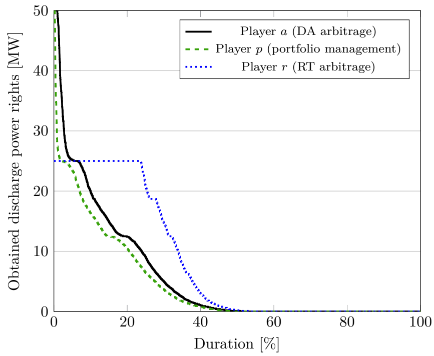
(a) Daily allocation of charge power rights.



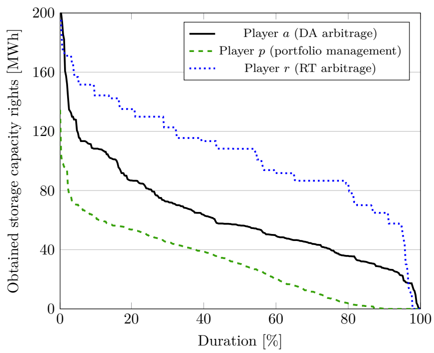
(b) Hourly allocation of charge power rights.



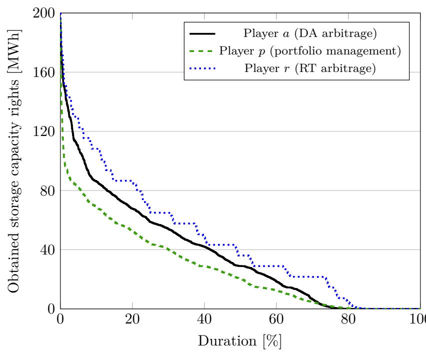
(c) Daily allocation of discharge power rights.



(d) Hourly allocation of discharge power rights.



(e) Daily allocation of storage capacity rights.



(f) Hourly allocation of storage capacity rights.

Figure 7.5: Allocation of physical storage rights in a daily auction with daily market-clearings (Fig. 7.5a, Fig. 7.5c, Fig. 7.5e), and hourly market-clearings (Fig. 7.5b, Fig. 7.5d, Fig. 7.5f), 2014.

not predefined. This can be accomplished by the development of a platform where periodical auctions with sequential market-clearings take place to allocate physical storage rights to use (dis)charge power capacities and energy storage capacity. These auctions allow storage owners to commercialize their resources over different applications, while players looking for additional flexibility can obtain this on a short-term basis. Alternatively, through such an allocation mechanism players can effectively share storage resources. The mechanism allocates the resources to the most valuable application for each market-clearing, based on the players' willingness-to-pay, which directly relates to the improvement of their objective value from a marginal improvement of the respective storage resource.

Players may be incentivized to participate in such a mechanism to share investment costs, mitigate associated risks, exploit economies of scale, overcome regulatory barriers, and merge time-varying and player-dependent flexibility needs. In addition, this may include positive effects for the system as well, as limited storage resources are allocated to the most valuable services at each point in time and the strategic operation of storage resources is likely to occur less frequently due to the introduced competition.

While this is not considered in the presented case study, the owner of the storage resources faces an optimization problem as well. The storage resources can either be supplied through the auction to be sold to other players, or can be used by the owner to participate in the electricity markets himself. Alternatively, and depending on the time of market closure of the storage auction with respect to the electricity markets, remaining storage capacity after the former can be used by the owner of storage resources to participate in the latter markets.

Chapter 8

Conclusions

Summary, conclusions, and suggestions for future work

8.1 Summary and conclusions

Electricity storage currently receives a lot of attention. This can be attributed to a combination of two factors: techno-economic developments in storage technologies[1] and increasing flexibility needs due to the ongoing integration of variable RES in the generation mix. Due to techno-economic constraints of power plants, and the limited ability to foresee RES generation, outages, and load behavior, the latter is most apparent in short-term electricity markets. These include the DA, ID, and RT balancing markets, and thus it is in these markets in which storage is financially rewarded for its flexibility.

The two factors mentioned above, together with the continuously updated design of the short-term electricity markets, set the scene for this thesis. It aims to contribute to the ongoing discussion on electricity storage by providing novel insights in its participation and modeling in short-term markets, and power systems in general, facing an increasing integration of variable RES. Such insights are important, as underestimating the value and role of storage could leave an important flexibility source underexploited, whereas overestimating the value and role of storage could lead to considerable development of a flexibility source that can possibly not be effectively valorized (yet).

[1] These include (1) improved technical performances, (2) decreased costs, and (3) new suitable locations for historically geographical-constrained technologies.

First, Chapter 2 presents a comprehensive introduction to electricity storage. Storage systems can be characterized by different techno-economic parameters, which most commonly, but not exclusively, include the (dis)charge power rating and duration, energy storage capacity, roundtrip efficiency, calendar and cycle-life, power and energy density, and investment cost. A wide range of technologies are available, with PHS, CAES, flywheels, supercaps, SMES, BES, fuel cells, and P2G being the ones most often considered for grid integration. Storage systems can be used for different applications: energy services include arbitrage and portfolio management; grid services include the provision of frequency control, congestion management, voltage support, and black-start service; reliability services include the support of reliability on the local level through back-up, UPS, and power quality management, and on the system level by providing firm generation capacity. The extent to which the different storage technologies can technically provide such services depends on their technical characteristics, while the extent to which they are well-suited for these services depends on their technical and economic characteristics, and for some services on their location (i.e., transmission or distribution grid, and location within those grids) as well.

Chapter 3 illustrates the system-level role and value of storage, and concludes that it is a valuable technology to support the transition to, and operation of, RES-based systems. A combined long-term investment and short-term operation model with high temporal and operational detail is presented, which allows to capture the interactions between capacity investment and energy and reserve scheduling. Storage is shown to decrease total system cost, which has a threefold explanation. First, storage compensates the system's expected variability by storing base load and RES generation in times of low residual demand, and replacing (high) peak generation in times of high residual demand, with the storage fuel cost decreasing with the RES share. Second, storage compensates the system's unexpected variability by providing reserve, thereby reducing the need for inefficient scheduling to accommodate must-run conventional generators. The interaction between energy and reserve scheduling leads to storage providing upward reserve at all RES targets, and downward reserve only at high RES targets. Third, RES targets can be achieved with less RES capacity, as excess RES generation can be stored instead of curtailed, or generated to be consumed since the incompressible part of supply is lower. In addition, both BES and PHS are shown to be valuable technologies. PHS is mainly developed to provide energy services and energy-intensive reserve products, while investments in BES mainly serve to provide power-related reserve products. Although they compete to provide some services, they complement each other to cover the overall demand for flexibility in the system. Finally, a relationship is shown between the imposed RES target and installed flexible resources. If due to capacity legacy or market design conventional flexible capacity is kept operational in the system, this thus affects the development of alternative flexibility sources.

Next, its participation in the short-term markets is studied from an operator's perspective in Chapter 5 and Chapter 6, and an innovative type of participation is introduced in Chapter 7. Since a good understanding of these markets is essential, Chapter 4 first reviews the design of these markets in detail for the CWE region, and analyzes the implications for flexibility. As such, insights in whether flexibility is treated consistently and appropriately among the different geographical and sequential markets are provided. Furthermore, desirable future reforms are identified. Highlighted reforms include the introduction of ID auctions, facilitation of passive balancing, increase of cross-border cooperation, and finer temporal resolutions. Trading volume analyses confirm that the DA market is by far the largest short-term market. Although the ID market plays a minor role in terms of trading volume, it has been increasing and is expected to keep on growing. Finally, the RT market has seen its share of consumption decrease due to improved RES output forecasts and profiling in the DA and ID market, and increased ID market liquidity, cross-border cooperation, and passive balancing. In conclusion, the details of market design are crucial to the successful integration of RES, as they define the opportunities for flexibility providers to valorize flexible operations. An open research question remains whether the current designs with energy-based remuneration are adequate in highly renewable power systems. Capacity markets, flexibility products, and operating reserve demand curves can present add-ons to fix current designs.

Chapter 5 studies the trading and operation of storage for a single application, being day-ahead market arbitrage. A comprehensive formulation of the arbitrage problem including detailed operating constraints is presented, along with a new methodology to account for the price-effect of storage, which dictates that storage generally reduces price spreads by increasing low prices and decreasing high prices. The most accurate available price-effect data is considered, published by several European power exchanges as so-called DA market resilience functions. These show piecewise linear relationships between quantity and price, for which a stepwise approximation is proposed that is able to reduce computational effort significantly while providing accurate lower and upper bound approximations. Results show that the price-effect cannot simply be ignored in trading and operation analyses for additional large-scale storage capacities. When optimizing as a price-taker, the power rating will always be used to its full capacity, unless bounded by the limited energy storage capacity. In contrast, considering the price-effect leads to (1) fewer full load hours to keep price spreads from diminishing too much, (2) more operational hours as actions are partially shifted to smoothen the price-effect, and (3) less (dis)charged energy in total. Due to the price-effect, a trade-off emerges between the capacity used and the average profit per unit. Finally, when using Belgian market data from 2014, results show that DA market arbitrage does not provide adequate revenues to compensate for the annualized investment cost of PHS in a wide range of scenarios.

Storage profitability requires aggregating applications, and co-optimizing them as use for one might interfere with use for others. As such, Chapter 6 extends the day-ahead market models to allow for the aggregation of arbitrage opportunities. All three short-term markets are considered, as well as the opportunity to engage in three types of arbitrage: intertemporal, intermarket, and intertemporal intermarket. In addition, the price-effect is studied for not only the DA market, but also for the ID market, and for the RT market by using custom-made piecewise linear RT market resilience functions. While the DA market is a conventional revenue source, the ID and RT markets include interesting new opportunities. Results show that the arbitrage potential for the coupled and harmonized DA markets is similar in the four CWE market zones, but not entirely for the partly coupled and harmonized ID markets, and not at all for the largely noncoupled and nonharmonized RT markets. As storage value differs between market zones, different locations have to be analyzed in investment decisions. Differences in storage value among the geographical and sequential markets are shown to relate to differences in market design. Aggregating arbitrage opportunities increases the storage value, with the aggregation method, i.e., separate or coordinated participation, determining the expected additional value, complexity, and risk. In addition, the price-effect is shown to be much stronger in the ID market and RT market compared to the DA market. Finally, the earlier observation stating that considering the price-effect leads to fewer full load hours, more operational hours, and less overall traded energy, is shown to be generally applicable independent from the considered short-term market.

The aggregation of applications can not only be achieved by one player, but also through the co-operation and sharing of storage resources by different players. As such, Chapter 7 discusses the design of a new market, or market product within existing markets, to enable such a multi-player storage use, and thus also the decoupling of storage investment and ownership from storage trading and operation. A periodically organized auction is presented to allocate storage resources through so-called physical storage rights between different market players. Similar to the case of the explicit auctioning of cross-border capacity through PTRs, first the right to use resources is auctioned, after which players can use these contracted resources. Incentives to participate may include the exploitation of economies of scale, mitigation of risk, matching of complementary flexibility needs, and overcoming of regulatory barriers. The storage value resulting from the proposed allocation mechanism is shown to outperform that from a range of fixed a priori allocations. Furthermore, market-clearings for shorter durations perform better. This ensures that the storage resources are allocated to the most valuable services at each point in time. The more players and applications are considered, the more the revenue collected through the auctioning of physical storage rights converges to the total captured value of the storage resources in the electricity markets.

8.2 Suggestions for future work

The suggestions for future work are categorized according to the performed analyses in the articles presented in Chapter 3 to Chapter 7.

Chapter 3: Role of electricity storage

There are five topics that are suggested for future work. First, an expansion of the geographical scope to include multiple neighboring market zones, allows to analyze the role and value of storage under different scenarios for the degree to which the considered system is interconnected. Due to the increasing coupling of markets, competition in flexibility supply not only has to be considered locally, but also across market zones in making operation and investment decisions. Second, an expansion of the flexibility sources including the participation of flexible demand, allows to study the impact of the price-responsiveness of the demand under different scenarios. Third, whereas the reservation of capacity to provide frequency control is modeled, including the activation of reserves presents a valuable addition to the current state-of-the-art. Fourth, once (a subset of) these model additions have been included, the developed model can be applied to advise specific systems' policy-makers on market design and energy policy, and market players on the investment in and operation of storage capacity. Fifth, the trade-off between using the available computational resources for accurately modeling short-term operation or to consider uncertainty regarding input parameters (e.g., fuel prices, investment costs, demand growth) should be investigated. This contributes to an efficient allocation of the computational resources to the right areas for each specific application.

Chapter 4: Short-term electricity markets

An important suggestion for future research includes the use of models or statistical methods to analyze how specific market design rules may affect the operation and development of different flexibility sources, generation technologies, and the operation of the system in general. This allows to quantitatively complement the qualitative study of the article presented in Chapter 4, thereby providing useful advice concerning future market redesigns.

Chapter 5: Single-application operation

Suggestions for future work include three topics. First, the estimation of a lower limit to the arbitrage value under uncertainty in addition to the presented upper limit, which allows to provide an operating profit range under imperfect price foresight. The combination of the relaxation of the perfect foresight assumption and the study of the price-effect has not been considered before. Second, analyzing the arbitrage application of storage in the context of a portfolio of generation, storage, and/or consumption units, allows to analyze the effect of storage ownership on its value and operation, and on other players through market prices. Third, more complex games in which competing players, both locally and in neighboring market zones, might react and change their behavior in response to entry of additional storage capacity is identified as an important future research topic as well.

Chapter 6: Multi-application operation

In addition to the three suggestions for future research discussed for the article presented in Chapter 5, which could also all be applied to the models developed in the article in Chapter 6, expanding the developed models to combine more storage applications provide a natural extension of the performed work. In first instance, the aggregation of both different arbitrage opportunities and the provision of different frequency control products is suggested for future research, but other services may present equally important topics for future work as well.

Chapter 7: Multi-player operation

Suggestions for future work include the comparison of the explicit auctioning of storage resources through physical storage rights to a centralized operation of storage with implicit auctioning and to financial storage rights. In addition, suggestions include the analysis of different design parameters of the presented auction (e.g., lead times between the auction and physical delivery, allocation horizon), as well as the accommodation of flexible demand in this flexibility platform because of the similarities with electricity storage (e.g., limited duration). Furthermore, whereas the provided illustrations and case study focus on the sharing and co-operation of large-scale storage by multiple players, the applicability to the aggregation of multiple small-scale and decentralized storage systems is suggested for future research. Finally, the integration of the presented auction-based allocation platform in the existing electricity market design, is identified as an important topic for future work.

Appendix A

Mixed complementarity problem formulations

A.1 Hourly market-clearings

First the MCP formulation for a periodically organized auction with hourly market-clearings for the shared storage resources is presented. The KKT conditions of player a are (A.1)-(A.10), while those of player p are (A.11)-(A.23), and finally the KKT conditions of player r are (A.24)-(A.34). The shared constraints are represented by (A.35)-(A.37) in the MCP formulation.

Player a:

$$0 \leq \lambda_h^{\mathrm{da,o}}/|\mathbb{H}| + T^{\mathrm{h}} \cdot \gamma_{a,h}^{\mathrm{e}} \cdot \eta^{\mathrm{c}} + \tau_{a,h}^{\mathrm{c}} \perp p_{a,h}^{\mathrm{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.1}$$

$$0 \leq -\lambda_h^{\mathrm{da,o}}/|\mathbb{H}| - T^{\mathrm{h}} \cdot \gamma_{a,h}^{\mathrm{e}}/\eta^{\mathrm{d}} + \tau_{a,h}^{\mathrm{d}} \perp p_{a,h}^{\mathrm{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.2}$$

$$0 \leq -\gamma_{a,h}^{\mathrm{e}} + \gamma_{a,h+1}^{\mathrm{e}} + \tau_{a,h}^{\mathrm{e}} \perp e_{a,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.3}$$

$$0 \leq -\tau_{a,h}^{\mathrm{c}} + \mu_h^{\mathrm{c}} \perp p_{a,h}^{\mathrm{c,max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.4}$$

$$0 \leq -\tau_{a,h}^{\mathrm{d}} + \mu_h^{\mathrm{d}} \perp p_{a,h}^{\mathrm{d,max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.5}$$

$$0 \leq -\tau_{a,h}^{\mathrm{e}} + \mu_h^{\mathrm{e}} \perp e_{a,h}^{\mathrm{max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.6}$$

$$0 = -e_{a,h} + e_{a,h\text{-}1} + T^{\mathrm{h}} \cdot \left(p^{\mathrm{c}}_{a,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{a,h}/\eta^{\mathrm{d}}\right),\ \gamma^{\mathrm{e}}_{a,h} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.7}$$

$$0 \leq p^{\mathrm{c,max}}_{a,h} - p^{\mathrm{c}}_{a,h} \perp \tau^{\mathrm{c}}_{a,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.8}$$

$$0 \leq p^{\mathrm{d,max}}_{a,h} - p^{\mathrm{d}}_{a,h} \perp \tau^{\mathrm{d}}_{a,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.9}$$

$$0 \leq e^{\mathrm{max}}_{a,h} - e_{a,h} \perp \tau^{\mathrm{e}}_{a,h} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.10}$$

Player p:

$$0 \leq \gamma^{\mathrm{g}}_{p,h} + T^{\mathrm{h}} \cdot \gamma^{\mathrm{e}}_{p,h} \cdot \eta^{\mathrm{c}} + \tau^{\mathrm{c}}_{p,h} \perp p^{\mathrm{c}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.11}$$

$$0 \leq -\lambda^{\mathrm{da,o}}_{h}/|\mathbb{H}| - T^{\mathrm{h}} \cdot \gamma^{\mathrm{e}}_{p,h}/\eta^{\mathrm{d}} + \tau^{\mathrm{d}}_{p,h} \perp p^{\mathrm{d}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.12}$$

$$0 \leq -\gamma^{\mathrm{e}}_{p,h} + \gamma^{\mathrm{e}}_{p,h+1} + \tau^{\mathrm{e}}_{p,h} \perp e_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.13}$$

$$0 \leq -\lambda^{\mathrm{da,o}}_{h}/|\mathbb{H}| + \gamma^{\mathrm{g}}_{p,h} \perp p^{\mathrm{g}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.14}$$

$$0 \leq \gamma^{\mathrm{g}}_{p,h} \perp p^{\mathrm{l}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.15}$$

$$0 \leq -\tau^{\mathrm{c}}_{p,h} + \mu^{\mathrm{c}}_{h} \perp p^{\mathrm{c,max}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.16}$$

$$0 \leq -\tau^{\mathrm{d}}_{p,h} + \mu^{\mathrm{d}}_{h} \perp p^{\mathrm{d,max}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.17}$$

$$0 \leq -\tau^{\mathrm{e}}_{p,h} + \mu^{\mathrm{e}}_{h} \perp e^{\mathrm{max}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.18}$$

$$0 = -A^{\mathrm{res,abs}}_{p,h} + p^{\mathrm{c}}_{p,h} + p^{\mathrm{g}}_{p,h} + p^{\mathrm{l}}_{p,h},\ \gamma^{\mathrm{g}}_{p,h} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.19}$$

$$0 = -e_{p,h} + e_{p,h\text{-}1} + T^{\mathrm{h}} \cdot \left(p^{\mathrm{c}}_{p,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{p,h}/\eta^{\mathrm{d}}\right),\ \gamma^{\mathrm{e}}_{p,h} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.20}$$

$$0 \leq p^{\mathrm{c,max}}_{p,h} - p^{\mathrm{c}}_{p,h} \perp \tau^{\mathrm{c}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.21}$$

$$0 \leq p^{\mathrm{d,max}}_{p,h} - p^{\mathrm{d}}_{p,h} \perp \tau^{\mathrm{d}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.22}$$

$$0 \leq e^{\mathrm{max}}_{p,h} - e_{p,h} \perp \tau^{\mathrm{e}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.23}$$

Player r:

$$0 \leq \lambda_h^{\text{rt,o}}/|\mathbb{H}| + T^{\text{h}} \cdot \gamma_{r,h}^{\text{e}} \cdot \eta^{\text{c}} + \gamma_{r,h}^{\text{l}} + \tau_{r,h}^{\text{c}} \perp p_{r,h}^{\text{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.24}$$

$$0 \leq -\lambda_h^{\text{rt,o}}/|\mathbb{H}| - T^{\text{h}} \cdot \gamma_{r,h}^{\text{e}}/\eta^{\text{d}} + \gamma_{r,h}^{\text{l}} + \tau_{r,h}^{\text{d}} \perp p_{r,h}^{\text{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.25}$$

$$0 \leq -\gamma_{r,h}^{\text{e}} + \gamma_{r,h+1}^{\text{e}} + \tau_{r,h}^{\text{e}} \perp e_{r,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.26}$$

$$0 \leq -\tau_{r,h}^{\text{c}} + \mu_h^{\text{c}} \perp p_{r,h}^{\text{c,max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.27}$$

$$0 \leq -\tau_{r,h}^{\text{d}} + \mu_h^{\text{d}} \perp p_{r,h}^{\text{d,max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.28}$$

$$0 \leq -\tau_{r,h}^{\text{e}} + \mu_h^{\text{e}} \perp e_{r,h}^{\text{max}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.29}$$

$$0 \leq L_r^{\text{max}} - p_{r,h}^{\text{c}} - p_{r,h}^{\text{d}} \perp \gamma_{r,h}^{\text{l}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.30}$$

$$0 = -e_{r,h} + e_{r,h\text{-}1} + T^{\text{h}} \cdot \left(p_{r,h}^{\text{c}} \cdot \eta^{\text{c}} - p_{r,h}^{\text{d}}/\eta^{\text{d}}\right),\ \gamma_{r,h}^{\text{e}} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.31}$$

$$0 \leq p_{r,h}^{\text{c,max}} - p_{r,h}^{\text{c}} \perp \tau_{r,h}^{\text{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.32}$$

$$0 \leq p_{r,h}^{\text{d,max}} - p_{r,h}^{\text{d}} \perp \tau_{r,h}^{\text{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.33}$$

$$0 \leq e_{r,h}^{\text{max}} - e_{r,h} \perp \tau_{r,h}^{\text{e}} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.34}$$

Shared constraints:

$$0 \leq P^{\text{c,max}} - p_{a,h}^{\text{c,max}} - p_{p,h}^{\text{c,max}} - p_{r,h}^{\text{c,max}} \perp \mu_h^{\text{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.35}$$

$$0 \leq P^{\text{d,max}} - p_{a,h}^{\text{d,max}} - p_{p,h}^{\text{d,max}} - p_{r,h}^{\text{d,max}} \perp \mu_h^{\text{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.36}$$

$$0 \leq E^{\text{max}} - e_{a,h}^{\text{max}} - e_{p,h}^{\text{max}} - e_{r,h}^{\text{max}} \perp \mu_h^{\text{e}} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.37}$$

A.2 Daily market-clearings

Second the MCP formulation for a less dynamic periodically organized auction (e.g., daily, weekly, monthly) including a single market-clearing, i.e., allocation, for each of the shared resources for the entire period (e.g., day, week, month) is presented. In this case, the KKT conditions of player a are (A.38)-(A.47), of player p are (A.48)-(A.60), and finally of player r are (A.61)-(A.71). The shared constraints are included through (A.72)-(A.74) in the MCP formulation.

Player a:

$$0 \leq \lambda_h^{\mathrm{da,o}}/|\mathbb{H}| + T^{\mathrm{h}} \cdot \gamma_{a,h}^{\mathrm{e}} \cdot \eta^{\mathrm{c}} + \tau_{a,h}^{\mathrm{c}} \perp p_{a,h}^{\mathrm{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.38}$$

$$0 \leq -\lambda_h^{\mathrm{da,o}}/|\mathbb{H}| - T^{\mathrm{h}} \cdot \gamma_{a,h}^{\mathrm{e}}/\eta^{\mathrm{d}} + \tau_{a,h}^{\mathrm{d}} \perp p_{a,h}^{\mathrm{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.39}$$

$$0 \leq -\gamma_{a,h}^{\mathrm{e}} + \gamma_{a,h+1}^{\mathrm{e}} + \tau_{a,h}^{\mathrm{e}} \perp e_{a,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.40}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau_{a,h}^{\mathrm{c}}) + \mu^{\mathrm{c}} \perp p_a^{\mathrm{c,max}} \geq 0, \tag{A.41}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau_{a,h}^{\mathrm{d}}) + \mu^{\mathrm{d}} \perp p_a^{\mathrm{d,max}} \geq 0, \tag{A.42}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau_{a,h}^{\mathrm{e}}) + \mu^{\mathrm{e}} \perp e_a^{\mathrm{max}} \geq 0, \tag{A.43}$$

$$0 = -e_{a,h} + e_{a,h\text{-}1} + T^{\mathrm{h}} \cdot \left(p_{a,h}^{\mathrm{c}} \cdot \eta^{\mathrm{c}} - p_{a,h}^{\mathrm{d}}/\eta^{\mathrm{d}}\right),\ \gamma_{a,h}^{\mathrm{e}} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.44}$$

$$0 \leq p_a^{\mathrm{c,max}} - p_{a,h}^{\mathrm{c}} \perp \tau_{a,h}^{\mathrm{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.45}$$

$$0 \leq p_a^{\mathrm{d,max}} - p_{a,h}^{\mathrm{d}} \perp \tau_{a,h}^{\mathrm{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.46}$$

$$0 \leq e_a^{\mathrm{max}} - e_{a,h} \perp \tau_{a,h}^{\mathrm{e}} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.47}$$

Player p:

$$0 \leq \gamma_{p,h}^{\mathrm{g}} + T^{\mathrm{h}} \cdot \gamma_{p,h}^{\mathrm{e}} \cdot \eta^{\mathrm{c}} + \tau_{p,h}^{\mathrm{c}} \perp p_{p,h}^{\mathrm{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.48}$$

$$0 \leq -\lambda_h^{\mathrm{da,o}}/|\mathbb{H}| - T^{\mathrm{h}} \cdot \gamma_{p,h}^{\mathrm{e}}/\eta^{\mathrm{d}} + \tau_{p,h}^{\mathrm{d}} \perp p_{p,h}^{\mathrm{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.49}$$

$$0 \leq -\gamma^{\mathrm{e}}_{p,h} + \gamma^{\mathrm{e}}_{p,h+1} + \tau^{\mathrm{e}}_{p,h} \perp e_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.50}$$

$$0 \leq -\lambda^{\mathrm{da,o}}_{h}/|\mathbb{H}| + \gamma^{\mathrm{g}}_{p,h} \perp p^{\mathrm{g}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.51}$$

$$0 \leq \gamma^{\mathrm{g}}_{p,h} \perp p^{\mathrm{l}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.52}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{c}}_{p,h}) + \mu^{\mathrm{c}} \perp p^{\mathrm{c,max}}_{p} \geq 0, \tag{A.53}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{d}}_{p,h}) + \mu^{\mathrm{d}} \perp p^{\mathrm{d,max}}_{p} \geq 0, \tag{A.54}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{e}}_{p,h}) + \mu^{\mathrm{e}} \perp e^{\mathrm{max}}_{p} \geq 0, \tag{A.55}$$

$$0 = -A^{\mathrm{res,abs}}_{p,h} + p^{\mathrm{c}}_{p,h} + p^{\mathrm{g}}_{p,h} + p^{\mathrm{l}}_{p,h}\ ,\ \gamma^{\mathrm{g}}_{p,h} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.56}$$

$$0 = -e_{p,h} + e_{p,h\text{-}1} + T^{\mathrm{h}} \cdot (p^{\mathrm{c}}_{p,h} \cdot \eta^{\mathrm{c}} - p^{\mathrm{d}}_{p,h}/\eta^{\mathrm{d}})\ ,\ \gamma^{\mathrm{e}}_{p,h} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.57}$$

$$0 \leq p^{\mathrm{c,max}}_{p} - p^{\mathrm{c}}_{p,h} \perp \tau^{\mathrm{c}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.58}$$

$$0 \leq p^{\mathrm{d,max}}_{p} - p^{\mathrm{d}}_{p,h} \perp \tau^{\mathrm{d}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.59}$$

$$0 \leq e^{\mathrm{max}}_{p} - e_{p,h} \perp \tau^{\mathrm{e}}_{p,h} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.60}$$

Player r:

$$0 \leq \lambda^{\mathrm{rt,o}}_{h}/|\mathbb{H}| + T^{\mathrm{h}} \cdot \gamma^{\mathrm{e}}_{r,h} \cdot \eta^{\mathrm{c}} + \gamma^{\mathrm{l}}_{r,h} + \tau^{\mathrm{c}}_{r,h} \perp p^{\mathrm{c}}_{r,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.61}$$

$$0 \leq -\lambda^{\mathrm{rt,o}}_{h}/|\mathbb{H}| - T^{\mathrm{h}} \cdot \gamma^{\mathrm{e}}_{r,h}/\eta^{\mathrm{d}} + \gamma^{\mathrm{l}}_{r,h} + \tau^{\mathrm{d}}_{r,h} \perp p^{\mathrm{d}}_{r,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.62}$$

$$0 \leq -\gamma^{\mathrm{e}}_{r,h} + \gamma^{\mathrm{e}}_{r,h+1} + \tau^{\mathrm{e}}_{r,h} \perp e_{r,h} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.63}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{c}}_{r,h}) + \mu^{\mathrm{c}} \perp p^{\mathrm{c,max}}_{r} \geq 0, \tag{A.64}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{d}}_{r,h}) + \mu^{\mathrm{d}} \perp p^{\mathrm{d,max}}_{r} \geq 0, \tag{A.65}$$

$$0 \leq \sum_{h \in \mathbb{H}} (-\tau^{\mathrm{e}}_{r,h}) + \mu^{\mathrm{e}} \perp e^{\mathrm{max}}_{r} \geq 0, \tag{A.66}$$

$$0 \leq L_r^{\max} - p_{r,h}^{\mathrm{c}} - p_{r,h}^{\mathrm{d}} \perp \gamma_{r,h}^{\mathrm{l}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.67}$$

$$0 = -e_{r,h} + e_{r,h\text{-}1} + T^{\mathrm{h}} \cdot \left(p_{r,h}^{\mathrm{c}} \cdot \eta^{\mathrm{c}} - p_{r,h}^{\mathrm{d}}/\eta^{\mathrm{d}}\right),\ \gamma_{r,h}^{\mathrm{e}} \in \mathbb{R}, \quad \forall\, h \in \mathbb{H}, \tag{A.68}$$

$$0 \leq p_r^{\mathrm{c,max}} - p_{r,h}^{\mathrm{c}} \perp \tau_{r,h}^{\mathrm{c}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.69}$$

$$0 \leq p_r^{\mathrm{d,max}} - p_{r,h}^{\mathrm{d}} \perp \tau_{r,h}^{\mathrm{d}} \geq 0, \quad \forall\, h \in \mathbb{H}, \tag{A.70}$$

$$0 \leq e_r^{\max} - e_{r,h} \perp \tau_{r,h}^{\mathrm{e}} \geq 0, \quad \forall\, h \in \mathbb{H}. \tag{A.71}$$

Shared constraints:

$$0 \leq P^{\mathrm{c,max}} - p_a^{\mathrm{c,max}} - p_p^{\mathrm{c,max}} - p_r^{\mathrm{c,max}} \perp \mu^{\mathrm{c}} \geq 0, \tag{A.72}$$

$$0 \leq P^{\mathrm{d,max}} - p_a^{\mathrm{d,max}} - p_p^{\mathrm{d,max}} - p_r^{\mathrm{d,max}} \perp \mu^{\mathrm{d}} \geq 0, \tag{A.73}$$

$$0 \leq E^{\max} - e_a^{\max} - e_p^{\max} - e_r^{\max} \perp \mu^{\mathrm{e}} \geq 0. \tag{A.74}$$

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Curriculum Vitae

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